BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

In the Matter of PUBLIC UTILITIES COMMISSION Instituting a Proceeding to Investigate Performance-Based Regulation	DOCKET NO. 2018-0088

INITIAL COMPREHENSIVE PROPOSAL OF THE HAWAIIAN ELECTRIC COMPANIES

EXHIBITS "A" THROUGH "F"

AND

CERTIFICATE OF SERVICE

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INITIAL COMPREHENSIVE PROPOSAL OF THE
HAWAIIAN ELECTRIC COMPANIES

The Hawaiian Electric Companies[1] respectfully submit this Initial Comprehensive Proposal ("Proposal") for the Commission's, Parties' and Participant's consideration and further discussion and deliberation in Phase 2 of this proceeding.[2]

I. INTRODUCTION AND SUMMARY

Consistent with Order No. 36388, the Hawaiian Electric Companies are proposing multiyear rate plan ("MRP" or "MYRP") provisions as well as Performance Incentive Mechanisms ("PIMs"), Scorecards and Reported Metrics for further development and refinement in Phase 2 of this docket.

As acknowledged during Workshop A (held on August 7, 2019), it is challenging to make definitive proposals before, among other things, (1) better understanding the potential financial implications, individually and collectively, of proposals; (2) certain variables are determined (i.e., individual elements of the Revenue Adjustment formula and mechanisms); and (3) the scope and interrelationship of proposals are clarified. The Companies understand and appreciate that the

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[1] Hawaiian Electric Company, Inc. ("Hawaiian Electric"), Maui Electric Company, Limited ("Maui Electric"), and Hawai'i Electric Light Company, Inc. ("Hawai'i Electric Light") are collectively referred to as the "Hawaiian Electric Companies" or "Companies."
[2] This Proposal is submitted pursuant to Order No. 36388 Convening Phase 2 and Establishing a Procedural Schedule, issued in this proceeding on June 26, 2019 ("Order No. 36388").

Phase 2 process is designed to progressively address these concerns by, for example, including a Workshop for financial modeling in November of 2019 and promoting an iterative process under which updated proposals will be presented in January and May 2020, with briefing to follow in June through August 2020. Based on this understanding, the Companies herein present initial comprehensive proposals subject to adjustment and refinement based on discussions, feedback and further evaluation during the remainder of Phase 2. At the same time, the Companies welcome the opportunity to collaborate and will remain open minded to proposals by others in this docket.

MRP

The Companies include comprehensive MRP proposals in section II below. Briefly stated, these include:

Control Period: The Commission's 5-year rate period (i.e., Control Period) would be implemented, provided that an adequate Annual Revenue Adjustment formula and modified MPIR Mechanism are approved. If practical, the new Multi-Year Rate Plan ("MYRP" or "MRP") would be put in place for Hawaiian Electric and Hawaii Electric Light in time for the first Adjusted Revenue Target to be effective January 1, 2021.

Base Rates: The initial base rates for a modified MYRP should be set in the "next" set of rate cases (including a 2019 test year for Hawaiʻi Electric Light, a 2020 test year rate case for Hawaiian Electric, and a 2021 test year for Maui Electric).

Target Revenues: The existing Revenue Adjustment Mechanism ("RAM") applies to Target Revenues resulting from the Results of Operations for the test year in a general rate case. The Companies propose to continue to set Base Target Revenues for the Annual Revenue Adjustment ("ARA") in the same manner.

Continuation of Revenue Decoupling and Adjustment Clauses: Existing cost trackers and pass-through mechanisms will continue to operate.

Elimination of ARA Lag: The Companies' propose use of an ARA formula that allows filing of the ARA in time for the Adjusted Revenue Target to be effective as of January 1st of each Adjustment Year. Thus, regulatory lag in accrual that exists with the current RAM can and should be eliminated.

ARA Formula: The Companies prefer that Base Target Revenue be adjusted each year during the Control Period (i.e., each Adjustment Year), resulting in an Adjusted Target Revenue for each year, rather than calculating an cumulative ARA amount that is added to the Base Target Revenue.

Inflation Index ("I"): The Companies propose to use the Gross Domestic Product Price Index ("GDP-PI" or "GDPPI") as the measure of inflation in the ARA Formula, despite its demonstrated deficiency as a measure of input cost inflation for the electric utility industry. The Companies proposal is conditioned upon accounting for the difference between GDP-PI and input cost inflation of electric utilities in the determination of "X".

Productivity Factor ("X"): The Companies propose that the X-factor should reflect the industry productivity trend and an inflation differential, which is the difference between the trends in the GDP-PI and the industry input prices. The Companies propose to set "X" for the Control Period using the Kahn methodology, as applied to a representative sample of 45 U.S. Vertically Integrated Electric Utilities ("VIEUs") over a representative period, which accounts for the

difference between GDP-PI and input cost inflation of electric utilities. The proposed value of X is -1.41%, pending further evaluation of the X-factor and financial analyses of the MRP proposals.[3]

Consumer Dividend ("CD"): The Companies do not believe justification has been established to implement a Consumer Dividend. Nevertheless, if a Consumer Dividend is to be adopted, the Companies conditionally propose to include a Consumer Dividend Factor of 0.22% in the ARA Formula. The Companies' position is also, however, that another Consumer Dividend is not warranted if and to the extent that a Customer Benefit Adjustment is made to the revenue requirement is setting base rates. Also, any Consumer Dividend must account for and not double count existing Company commitments and obligations, such as the existing Customer Benefit revenue reductions established in rate cases, and the net benefits to be delivered to customers associated with the new ERP/EAM system.

MPIR Mechanism: The Companies propose the following clarifications and/or modifications for the MPIR mechanism:

- Clarify that major projects for equipment or facilities for new developments or unserved areas or to serve growth in an area would be eligible for MPIR recovery.
- Clarify the MPIR Guidelines to explicitly allow recovery of deferred costs and other expenses of a major project or program. This would address capital bias concerns with the MPIR mechanism.
- Allow the inclusion of the full investment amount in the MPIR rate base for recovery in the year the project goes into service.

[3] Attached to this proposal filing as Exhibit "A" is an updated report prepared by Pacific Economics Group Research LLC ("PEG") entitled "Designing Revenue Adjustment Indexes for Hawaiian Electric Companies", dated August 13, 2019, which summarizes the basis for and calculation of the X-factor proposed by the Companies.

Z-Factor ("Z"): The Companies propose to include a Z-factor in the ARA formula to account for exceptional circumstances not in the utility's direct control (e.g., tax law changes). The detailed proposal includes Z-factor Eligibility Criteria, generic and specific examples of Z-factor events, annual Z-factor Materiality Thresholds (of $4 million per event for Hawaiian Electric, and $1 million per event for Hawaii Electric Light and Maui Electric), and Z-factor Filings details.

Cost of Capital Adjustment Mechanism ("COCAM"): The Companies propose that the California method of setting the cost of capital in a separate consolidated proceeding (rather than in the Companies' separate rate cases), and adjusting the cost of capital ("COC") in between such separate proceedings, be adopted in Hawaii. The Companies propose to include a Cost of Capital ("COC")-factor in the target revenue adjustment formula or the Z-factor. The COC-factor, which could be negative or positive, would be determined using a new Cost of Capital Adjustment Mechanism ("COCAM"). The COCAM would be used to periodically determine the COC (i.e., the rate of return on rate base) used in determining the revenue requirement in general rate cases, and the revenue requirement impact of capital projects included in the MPIR or in the Z-factor.

Earnings Sharing Mechanism ("ESM"): The Companies propose a symmetric ESM. The detailed proposal includes proposed dead bands, sharing bands and sharing percentages within each band. The rate of return on common equity ("ROE") used in the ESM would be determined on a ratemaking basis. The Companies also propose to include incentive credits and penalties in calculating the ratemaking ROE.

Rate Design during Control Period: The Companies propose that the Commission, by order on its own motion, or upon petition by the Company for good cause shown, initiate a revenue neutral proceeding during the Control Period to reallocate revenues among customer classes, and/or redesign the rates within customer classes.

Re-setting Base Rates After Initial Control Period: The Companies propose that, at the end of the initial control period, another set of rate cases or a consolidated rate case be used to reset base rates. The Companies propose that the test year for a consolidated rate case be calendar year 2025, and the Companies be permitted to file such a consolidated rate case as early as May 1, 2024 (based on a test year waiver).

Off-Ramps: The Companies propose to include an off ramp provision with two ROE triggers and a catastrophic events trigger. If an off ramp trigger occurs, then the Commission will determine what the appropriate remedy is. Appropriate remedies may include, but are not limited to, having the Company file a general rate case application, and adjusting parts of the ARA formula pending the effective date of new rates set in the general rate case.

Implementation Details: The Companies' proposals include preliminary implementation details (such as filing dates) where practical.

Performance Mechanisms

With respect to performance mechanisms, in most cases, the Companies have made more than one proposal for PIMs, Scorecards and Reported Metrics for the purpose of comparison and discussion. However, consistent with the Phase 2 guiding principle of Administrative Efficiency, and the outcome of cost control, the Companies recommend that generally only one scorecard and reported metric be established for each outcome. Very briefly, the Companies are making these proposals:

Interconnection Experience: A PIM with a reward or penalty based on timeliness in providing conditional approval of interconnection applications for DER systems less than 100kW. The Companies also propose Scorecards for surveys of customers' and contractors' experience with

the DER interconnection process; and the Independent Power Producer ("IPP") interconnection experience.

DER Asset Effectiveness: Two PIMs are proposed. With certain variations, these PIMs would reward the Companies for integrating various forms of DER.

Grid Investment Efficiency: A Shared Savings Mechanism is proposed based on utilization of Non-Wires Alternatives (NWAs).

Customer Engagement: A PIM is proposed to reward Advanced Meter adoption (i.e., "opt-ins") measured annually against Advanced Meter installation targets. Alternative Scorecards are proposed to measure and track (1) customer usage of a customer portal; and (2) time of use (TOU) rate option participation.

Cost Control: A scorecard is proposed to measure and track certain Operation and Maintenance ("O&M") expenses: Consolidated A&G, Transmission and Distribution and Customer Services costs per customer. These consolidated costs would be compared to how the Companies perform against a predetermined baseline. A&G expenses would exclude pension and benefits, as well as expenses for injuries/damages and regulatory commission expenses, consistent with how it appears this category of expenses was used for benchmarking in the Staff's February 7, 2019 Proposal.

GHG Reduction: Two Scorecards are proposed. The first would report and track carbon emissions in tons per year (for each island and also consolidated). The second would report and track carbon emission intensity in grams/kWh per year (for each island and also consolidated).

Electrification of Transportation: Reported Metrics are proposed for number of public charging stations and mid-day energy delivered from Company-owned charging stations.

Capital Formation: Reported Metrics are proposed for building permit value of rooftop PV deployed per island and megawatts of third party generation on the system.

Resilience: Reported Metrics are proposed for incident and emergency response certification and training.

Affordability: Reported Metrics are proposed for residential monthly bills and monthly bills as a percentage of low income customers.

Customer Equity: Reported Metrics are proposed for participation of low income customers in CBRE and subsidization costs with respect to DER.

II.

MULTI-YEAR RATE PLAN PROPOSALS

II. MULTI-YEAR RATE PLAN ("MYRP" OR "MRP") PROPOSALS

A. GENERAL CONSIDERATIONS

1. General Commission Guidance

a. By Decision and Order No. 36326 ("D&O 36326"), issued May 23, 2019, in Docket No. 2018-0088, the Commission establishes the regulatory principles, goals, and outcomes to guide Phase 2, and identifies a portfolio of specific PBR mechanisms for prioritized examination and development. D&O 36326 at 1-2.

b. The PBR mechanisms prioritized for Phase 2 are intended by the Commission to streamline regulatory requirements and reduce risk for utilities and their customers. By automatically adjusting utility revenues based on an annual revenue formula and employing an "upside" and "downside" earnings sharing mechanism, utilities will have greater certainty and more timely recognition of revenues. D&O 36326 at 4.

c. The PBR mechanisms to be examined and developed in Phase 2 will set a target revenue amount that encourages near-term cost savings for customers. The utility will have the opportunity to earn additional performance revenue if it achieves identified objectives, including improved customer engagement and DER performance. Earnings will be shared with utility customers in a way intended to maintain the utility's financial health, while passing cost savings on to customers. D&O 36326 at 5.

d. The Commission established the following guiding principles ("Principles") suggested in the Staff Proposal to inform the development of PBR mechanisms in Phase 2:[4]

• A customer-centric approach. A PBR framework should encourage the expanding opportunities for customer choice and participation in all appropriate aspects of utility system functions, including verifiable "day-one" savings for customers.

• Administrative efficiency. PBR offers an opportunity to simplify the regulatory framework and enhance overall administrative efficiency.

• Utility financial integrity. The financial integrity of the utility is essential to its basic obligation to provide safe and reliable electric service for its customers and a PBR framework is intended to preserve the utility's opportunity to earn a fair return on its business and investments, while maintaining attractive utility features, such as access to low-cost capital.

e. The Commission adopted the three regulatory goals ("Goals'") and the twelve prioritized outcomes ("Outcomes") suggested in the Staff Proposal. D&O 36326 at 6.

2. Existing MRP for Hawaiian Electric Companies

[4] D&O 36326 at 5-6.

This proceeding will modify the existing MYRP that is currently part of the decoupling mechanism for the Companies. The regulatory framework for the Hawaiian Electric Companies currently incorporates, in at least some form, several of the fundamental components ordinarily associated with PBR, including an MRP (fixed three-year cycle for general rate cases), an interim-period revenue adjustment mechanism (or "RAM") subject to a revenue cap, a revenue decoupling mechanism, and an Earnings Sharing Mechanism ("ESM"). Exceptions to limitations by the RAM Cap may be allowed on a case-by-case basis in accordance with MPIR guidelines. In addition, several Performance Incentive Mechanisms ("PIMs") are already in place, and others are actively being contemplated, including PIMs rewarding successful implementation of new renewable programs and procurement of utility-scale renewable generation.[5]

B. COMMISSION'S MRP GUIDANCE

1. Control Period: Phase 2 will focus on the development of requirements for a five-year MRP, rather than maintaining the status quo triennial rate case cycle, in order to amplify cost containment incentives.

2. Annual Revenue Adjustment: According to the Commission,[6] the MRP will feature an attrition relief mechanism, in the form of an index-driven annual revenue adjustment ("ARA"), to provide revenue adjustments during the five-year MRP. The determination of the specific factors included in the ARA formula, set out below, will be the subject of examination and discussion in Phase 2:

Annual Revenue Adjustment = (Inflation Factor) - (X-Factor) + (Z-Factor) - Customer Dividend

"[T]he commission's formula establishes an 'Annual Revenue Adjustment,' rather than a 'Revenue Cap Index.'" D&O 36326 at 30.

Allowed revenues in the years of the MRP period would be adjusted by an externally-indexed revenue formula, rather than by adjustments determined by the utility's actual costs. D&O 36326 at 8 n.6.

The Commission provided the following definitions:[7]

- Inflation Factor: Annual change according to a published inflation index

- X-Factor: Predetermined annual productivity factor

- Consumer Dividend Factor: A "stretch factor" or reduction in allowed revenues

[5] Order No. 35411 at 39-41, 43, 49.
[6] D&O 36326 at 8.
[7] D&O 36326 at 29, n.32.

• Z-Factor: Factor applied (ex post) to account for exceptional circumstances not in the utility's direct control (e.g., tax law changes)

3. Elimination of Lag: "The commission will consider measures to reduce lag in implementing the accrual and/or collection of approved revenues."

4. Earnings Sharing Mechanism ("ESM"): Phase 2 will prioritize examination of an ESM that provides both 'upside" and "downside" sharing of earnings between the utility and customers when earnings fall outside a commission-approved non-adjustment range or "deadband", though not necessarily symmetrical amounts.

5. Base Rates: The Commission will utilize the existing or pending rate cases, respectively, in setting their target revenues for the initial MRP.

6. Continuation of Existing Tracking and Pass-Through Mechanisms: Existing cost trackers and pass-through mechanisms will continue to operate (e.g., Energy Cost Recovery Clause ("ECRC"), Purchased Power Adjustment Clause ("PPAC"), pension and other post-employment benefits tracking mechanisms, Renewable Energy Infrastructure Program ("REIP") surcharge, Demand-Side Management surcharge ("DSM Surcharge"), etc.), unless otherwise ordered by the Commission. D&O 36326 at 13, 36.

7. Revenue Decoupling and Revenue Balancing Account ("RBA"): The Commission will continue to utilize revenue decoupling (i.e., the RBA) to "true up" appropriately adjusted recorded revenues to an approved revenue target, thus ensuring that the utility recovers its approved target revenue, regardless of increases or decreases in energy sales or other revenue determinants. Revisions to the RBA may be considered to reduce lag and streamline the existing accrual, recovery, and reconciliation process, and to accommodate other potential regulatory changes discussed in Phase 2. D&O 36326 at 12-13, 35-36.

8. Rate Design: "Due to development of a MRP, as well as other revenue adjustment mechanisms under consideration, the commission recognizes that there will likely be a need to examine changes to the Companies' rate design structure during the MRP. Such rate design revisions are expected to be revenue neutral (i.e., not affecting the revenues set by the ARA) and will be addressed in a separate proceeding." D&O 36326 at 32.

C. COMPANIES' DETAILED MRP PROPOSALS

1. Target Revenues

a. RAM Target Revenues

• The existing Revenue Adjustment Mechanism ("RAM") applies to Target Revenues resulting from the Results of Operations for the test year in a general rate case. In general, the target revenues include the revenue requirements (which reflects the gross up for revenue taxes) for (1) Operating and Maintenance ("O&M") Expenses, excluding Pension and OPEB expenses (since Pension and OPEB costs are the subject of Pension and OPEB Trackers) (the "O&M")

component, (2) Depreciation and Amortization Expenses (the "Depreciation" component), and (3) the Rate of Return times Rate Base plus income taxes (the "rate base return" component). Fuel and purchased power expenses are not included in target revenues. (The revenue requirement impact of other adjustments to the test year Results of Operations also may be included in Target Revenues.)

b. Company's Proposal

• The Companies propose to continue to set Base Target Revenues for the ARA in the same manner.

• The existing RAM results in a cumulative adjustment to the Target Revenues developed in a rate case. The Companies, however, propose to adjust the Target Revenue amount each year during the Control period by the ARA amount applicable to the adjustment year, so that the ARA amount for an adjustment year is the incremental amount of the change in the Adjusted Target Revenues for the prior year. This will provide greater transparency into the year-by-year effect of the ARA mechanism.

• Note that there are other adjustments that may be added to or subtracted from the Adjusted Target Revenues amount for a given year, due to the operation of the Z-factor and the MPIR mechanism. Certain Z-factor events (such as a change in the tax laws) may result in a change to the Adjusted Target Revenues amount, instead of an addition to the Adjusted Target Revenues amount.

• In the alternative, the ARA can continue to be applied in a way that results in a cumulative adjustment to the Target Revenues developed in a rate case, and the Company making the adjustment can separately report the year-over-year increase in the Target Revenues amount.

2. Continuation of ECRC, PPAC, Pension/OPEP Cost Trackers

a. Commission Guidance

• Existing cost trackers and pass-through mechanisms will continue to operate (e.g., Energy Cost Recovery Clause ("ECRC"), Purchased Power Adjustment Clause ("PPAC"), pension and other post-employment benefits tracking mechanisms, Renewable Energy Infrastructure Program ("REIP") surcharge, Demand-Side Management surcharge ("DSM Surcharge"), etc.), unless otherwise ordered by the Commission.

b. Companies' Proposal

• Existing cost trackers and pass-through mechanisms will continue to operate.

3. Continuation of Revenue Decoupling (and RBA)

a. Commission Guidance

• The Commission will continue to utilize revenue decoupling (i.e., the RBA) to "true up" appropriately adjusted recorded revenues to an approved revenue target, thus ensuring that the

utility recovers its approved target revenue, regardless of increases or decreases in energy sales or other revenue determinants. Revisions to the RBA may be considered to reduce lag and streamline the existing accrual, recovery, and reconciliation process, and to accommodate other potential regulatory changes discussed in Phase 2.

b. Companies' Proposal

- Revenue decoupling will be continued.

- Revisions to the RBA will be made to reduce lag and streamline the existing accrual, recovery, and reconciliation process, and to accommodate other changes made in Phase 2.

4. Control Period

a. Commission Guidance

- Phase 2 will focus on the development of requirements for a five-year MRP. D&O 36326 at 8. The Commission found that: "The development of a five-year MRP represents a reasonable step towards transitioning to a longer control period between rate cases, providing the utility with an operational environment similar to a competitive market structure." D&O 36326 at 28.

b. Companies' Proposal

- The Companies propose that Commission's 5-year rate period (i.e., Control Period) be implemented, provided that an adequate Annual Revenue Adjustment formula and MPIR Mechanism are approved.

- If practical, the new MRP would be put in place for Hawaiian Electric and Hawaii Electric Light in time for the first Adjusted Revenue Target to be effective January 1, 2021.

5. Elimination of RAM Lag

a. Commission Guidance

"The commission will consider measures to reduce lag in implementing the accrual and/or collection of approved revenues."

b. Companies' Proposal

- A simplified RAM formula should be adopted and the regulatory lag in accrual of the ARA can and should be eliminated. The new ARA is a simplified formula and would provide an additional cost containment incentive. In essence, there would be a single escalator for the target revenues, and the MPIR mechanism would be continued.

- The Companies' propose use of an ARA formula that allows filing of the ARA in time for the Adjusted Revenue Target to be effective as of January 1st of each Adjustment Year.

• The proposed implementation details are addressed later in this proposal filing.

• The alternative is to continue to file in time for the Adjusted Target to be effective as of June 1st, but for the Companies to accrue the increase in revenue from January 1st, as Hawaiian Electric was allowed to from 2014 through 2016.

6. Setting Base Rates

a. Commission Guidance

The Commission will utilize the existing or pending rate cases, respectively, in setting their target revenues for the initial MRP.

b. Companies' Proposal

• The Companies propose that the initial base rates for a modified MRP be set in the "next" set of rate cases (including a 2019 test year for Hawai'i Electric Light, a 2020 test year rate case for Hawaiian Electric, and a 2021 test year for Maui Electric).

• The current series of rate cases can be conducted within a reasonable time frame. For Hawaii Electric Light, the "next" rate case was filed December 14, 2018 in Docket No. 2018-0368. An interim increase in revenue should be authorized by no later than mid-November 2019. A modified ARA formula and longer control period could be implemented in 2021, after the conclusion of this proceeding. For Hawaiian Electric, the rules permit the filing of the next rate case based on a 2020 test year should be filed in the second half of 2019. An interim increase in revenue then should be authorized before the end of 2020. A modified ARA formula and longer control period could be implemented in 2021, after the conclusion of this proceeding. For Maui Electric, the rules permit the filing of the next rate case based on a 2021 test year as early as July 1, 2020. An interim increase in revenue then should be authorized by no later than June 2021. A modified ARA formula and longer control period could be implemented in 2022.

c. General Considerations

• MYRP authorities have stated that the "initial test year rates should be set in the course of a full rate case, applying traditional ratemaking practices and principles, and with meaningful input from consumer advocates and other stakeholders."[8]

• A PBR plan should be founded upon cost-based rates determined in the same way as a traditional general rate case. Incentives can then be layered on top of the cost based rates to modify the cost-based rates foundation and encourage desired outcomes.

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[8] M. Lowry & T. Woolf, *Performance-Based Regulation in a High Distributed Energy Resources Future* (Berkeley Lab Jan. 2016) ("*Lowry & Woolf PBR Technical Report*"), at 16.

• Without a new base rate case, the starting point for an extended control period would not be reasonable. The Companies are not earning their authorized returns under the existing base rates and MRP adjustments. If the Companies currently were earning in excess of their authorized returns, consumer representatives would maintain that a new rate case would be required.

7. Attrition Relief Mechanism (Target Revenue Adjustment Formula)

a. Commission Guidance

Annual Revenue Adjustment = (Inflation Factor) - (X-Factor) + (Z-Factor) - Customer Dividend

• Inflation Factor: Annual change according to a published inflation index

• X-Factor: Predetermined annual productivity factor

• Consumer Dividend Factor: A "stretch factor" or reduction in allowed revenues

• Z-Factor: Factor applied (ex post) to account for exceptional circumstances not in the utility's direct control (e.g., tax law changes)

b. Companies' Proposed Adjustment Formula

• A typical revenue cap has the form of "I – X", where I is a measure of inflation and X is a measure of expected productivity growth over the PBR term that is external to the regulated firm and is typically representative of some industry average.

• The (I – X) formula is often supplemented with a "Z-factor", as proposed by the Commission, that allows the cap to be adjusted for one-time factors that are outside the control of the regulated firm and that are not already reflected in the cap formula. The basic principle is that the regulated firm should not unduly benefit from nor be unduly harmed by events that are outside of its control (i.e., exogenous).

• The (I – X) formula can be supplemented by subtraction of a Consumer Dividend or stretch factor, as proposed by the Commission.

• The (I – X) formula also can be supplemented with a "K-factor" (such as the MPIR Mechanism in Hawaii) that captures the incremental revenue requirements for program and projects costs that are not captured by the (I – X) formula.

• The Companies propose to use a formula of "I – X - CD" to adjust target revenue, with "I" equal to the year-over-year change in the GDP-PI, "X" equal to industry productivity for more recent 15-year and 20-year periods, determined using the simplified Kahn methodology, and CD equal to .22%. The 2019 GDP Price Index was 2.1%. The Companies propose to set "X" for the Control Period using PEG's application of the Kahn methodology, as applied to a representative sample of 45 U.S. Vertically Integrated Electric Utilities ("VIEUs") over a representative period, which accounts for the difference between the GDP-PI and input cost inflation of electric

utilities. The proposed value of X is -1.41%, pending further evaluation of the X-factor and financial analyses of the MRP proposals. In PEG's "featured" run, the indicated Kahn X-factor was -**1.04**% for the full 1997-2017 sample period. The X-factor was even more negative for more recent sample periods, falling to -**1.41**% for the last fifteen years (2003-2017) and to -**2.35**% for the last 10 years (2008-2017). In these calculations, PEG found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. Given the increasingly negative value of the X-factor, use of the value for the last 15 years, rather than the value for the last 10 years, is somewhat conservative. The inclusion of a Customer Dividend ("CD") in the formula is subject to certain conditions, as addressed below.

• The Companies propose to supplement the (I – X) formula with a "Z Factor" and the MPIR Mechanism.

c. Companies' Proposed "I" Factor

• The "I" Factor is intended to be a measure of inflation that is external to the firm. There are two basic approaches to its determination. The first approach uses some measure of industry input inflation as the I Factor. The second approach is to use a measure of economy-wide output inflation, such as the GDP-PI. This approach is the most common in U.S. incentive regulation plans.

• Under the first approach, the "I – X" formula is simply industry input price growth less industry TFP growth. If the I factor is based on a measure of economy-wide **output** inflation, then the difference between this measure and industry **input** inflation should be taken into account. There are several ways to do this:

(i) The X-factor based on expected industry productivity "growth" can be adjusted for the expected difference between the measure of economy-wide **output** inflation and expected industry **input** inflation.

(ii) The X-factor can be based on the differences in productivity and input price growth between the industry and the overall economy. The allowed rate of change of the price cap index is equal to the rate of general price inflation in the aggregate economy less an adjustment factor (the X-factor), where the adjustment factor equals: (a) the difference between the targeted rate of industry total factor productivity growth and economy-wide total factor productivity growth (the "TFP differential"); and (b) the difference between the rate of economy-wide input price growth and industry input price growth (the "input price differential").

(iii) The expected difference between the measure of economy-wide **output** inflation and expected industry **input** inflation can be accounted for as an implicit stretch factor justifying a more inclusive K-Factor.

• The Companies' proposal is to use the GDP-PI for the "I" Factor. GDP-PI is the most commonly used factor, and is used in the existing RAM Cap. The determination of an appropriate industry input price inflator can be complex and difficult. However, the Companies'

consultants have provided input on the expected difference between the measure of economy-wide **output** inflation and expected industry **input** inflation.[9]

d. Companies' Proposed "X" Factor

• The X-factor is based on industry expected annual productivity growth. The productivity concept typically used is total factor productivity ("TFP"), which is defined as the ratio of total output to total input. Productivity gains are measured as the percentage change in TFP, which is computed as the percentage change in total output less the percentage change in total input. For example, if TFP growth is equal to 2.0%, this means that the same output can be produced with 2.0% fewer inputs, or the same quantity of inputs will yield 2.0% more output. On the other hand, if TFP growth is equal to -2.0%, this means that the same output is produced with 2.0% greater inputs, or the same quantity of inputs will yield 2.0% less output.

• Although X is typically determined by a productivity study that, by its very nature, is based on historical information, X is forward-looking as it is based on what differentials are expected over the course of the PBR term. That is, the historic TFP (and input price) study is used as a predictor of expected performance over this period.

• The parameters included in X may depend on the specification of the inflation term, "I". If "I" is a measure of industry input prices, X is determined by expected industry productivity growth. Conversely, if I is a measure of economy-wide output price growth (such as the GDP-PI), then, X consists of a differential in expected productivity growth between the industry and the overall economy, and a differential in input price growth between the overall economy and the industry. (I.e., the X-factor should reflect the industry productivity trend and an inflation differential, which is the difference between the trends in the GDP-PI and industry input prices.)

• Electric utility industry productivity growth has been negative, not positive, during recent periods. This is due to growth in the capital project cost inputs at rates significantly higher than inflation, rather than growth in non-fuel O&M expenses. One reason is the marked cost impact of replacing old assets, which are valued in historical dollars.

• Data showing the rate base growth rates for other vertically integrated electric utilities ("VIEUs")[10] was included in Exhibit E to the Companies' RSOP. The average compound annual growth rate for the 45 VIEUs was 5.86% for the 1997-2017 period, 6.98% for the 2002-2017 period, and 7.94% for the 2007-2017 period. In this most recent period, 11 of the VIEUs had average compound annual growth rates for rate base exceeding 10%.

• Incentive regulation provides the utility the flexibility to pursue cost-reduction initiatives and to keep the benefit of those reductions until rates are reset in the future. This is true regardless of whether the X-factor is positive or negative as the efficiency incentives derive from breaking the

[9] PEG reported that the tendency of the GDP-PI to underestimate utility input price inflation is a major reason that the current RAM cap is not compensatory, and that possible inaccuracy of the GDP-PI as a utility inflation measure has been recognized by regulators.
[10] The data was provided by PEG for the VIEUs used in its X-factor analyses.

linkage between revenues and costs. In other words, what is critical is that the X-factor not vary with the individual firm's actual performance.

• PEG reported that (1) X-factors have trended downward over time, (2) the average X-factor in current U.S. and Canada plans is 0.07%,[11] and the average value of the X-factor in current U.S. plans is -1.40%.

• The Companies' proposal is to determine the X-factor using the simplified Kahn methodology, as calculated by PEG. This method is still used by FERC to set the X-factors of interstate oil pipelines. The current oil pipeline index escalates prices by the Producer Price Index for Finished Goods plus 1.23%, implicitly indicating an X-factor of -1.23%. The prior oil pipeline index escalated prices by the Producer Price Index for Finished Goods plus 2.65%, indicating an X-factor value of -2.65%.

• Attached to this proposal filing as Exhibit "A" is an updated report prepared by PEG entitled "Designing Revenue Adjustment Indexes for Hawaiian Electric Companies", dated August 14, 2019. This report summarizes the basis for and calculation of the X-factor proposed by the Companies.

• PEG calculated values for the X-factor using the simplified "Kahn" methodology for a twenty-one-year (1997-2017) period, as well as shorter and more recent periods. PEG gathered a sample of publicly available data on the operations of 45 U.S. VIEUs to calculate the X-factor that would have been compensatory on average had they been subject to revenue adjustment indexes featuring GDP-PI as the inflation measure. This "Kahn method" calculation considers the appropriate inflation differential as well the base productivity trend, but does not itemize them. For all sample periods considered, the average annual growth in cost was considerably more rapid than the average annual growth in the GDP-PI.

• According to PEG, theoretical analysis suggests that a revenue adjustment index should have a scale escalator that measures growth in the operating scale of the subject utility. For vertically integrated utilities such as the Hawaiian Electric Companies, it makes sense to consider a multidimensional scale index that takes a weighted average of growth in the scale of generation, transmission, and distributor services. If the revenue adjustment index does not have a scale escalator, the expected growth in the scale of the utility is an implicit stretch factor.

• Using the scale index, the indicated Kahn X-factor was **-1.04%** for the full 1997-2017 sample period. The X-factor was even more negative for more recent sample periods, falling to **-1.41%** for the last fifteen years (2003-2017) and to **-2.35%** for the last 10 years (2008-2017). In these calculations, PEG found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. The rate base grew especially rapidly, and its growth tended to accelerate materially after 2006.

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[11] This average is raised considerably by the fact that many current plans are in Canada. Industry-specific inflation measures are more common in Canada, which reduces the need to compute productivity differentials.

• The Companies' proposed value of X is -1.41%, pending further evaluation of the X-factor and financial analyses of the MRP proposals. Given the increasingly negative value of the X-factor, use of the value for the last 15 years, rather than the value for the last 10 years, is somewhat conservative.

e. Use of (I – X) Formula

• The (I – X) formula is a one-size fits all formula, since it is based on the industry productivity trend (and industry cost trend). It is broadly recognized, however, that one size does **not** fit all, and that each utility will actually be different. For example, the Hawaiian Electric Companies are not electric distribution utilities, and most electric utility MYRPs were developed and implemented for distribution utilities. The Hawaiian Electric Companies are vertically integrated electric utilities, with a strong mandate to acquire cost-effective clean energy resources, to integrate distributed energy resources, to empower customer choice, to operate and maintain reliable, resilient and secure grids, and to take the steps necessary to accomplish these goals, including modernizing their grids. These mandates are expected to result in the occurrence of higher operating and capital project costs.

• The productivity growth of a utility is influenced by many drivers that are beyond a utility's control. For example, slow demand growth reduces opportunities to increase capacity realization and to realize incremental scale economies. An unusual number of assets nearing retirement age can create an outsized need for capex. It is possible, then, for the expected productivity growth of a utility to differ from the industry trend for reasons that are beyond its control.

• To account for these differences, (I –X) also can be determined based on the utility's estimated expenditure trend for the control period, taking into account the revenues that could be provided by the MPIR. The benefit of this approach is the tie to approved plans, and the financial integrity principle, while maintaining incentives to control costs (since revenues are not based on actual costs incurred during the control period). The downside of this approach is the lack of an updated PSIP, with the IGP process still in its early stages. Thus, the utility's estimated expenditure trend for the control period, taking into account the revenues that could be provided by the MPIR, can be used to **test** the viability of the formula in the plan.

• The Brattle Group documented several examples of regulators in the United States and elsewhere that have permitted above-inflation revenue increases (e.g., California, New York, Australia, Great Britain). These revenue increases were based on the business plans and corresponding financial forecasts put forward by the utility and tested in a rate case. In California, for the period 2007 to 2018, authorized revenues for the three major utilities increased on average by 2.5% per year above the rate of GDP-PI.

• The Brattle Group provided a table in Exhibit D showing the magnitude of the X- and K-factors of three MYRPs in the United States and Canada where the annual revenue adjustment is at least partly based on an external benchmark. All three include an additional annual revenue adjustment over and above the externally-determined benchmark to address capital. In the case

of Eversource, there is a capital tracker which recovers certain expenditures on a flow through basis.

Table 1: Summary of revenue adjustments based on an external benchmark

			Annual revenue	
			decrease due to	increase due to
State / Province	Utility		X-factor	K-factor
Massachusetts	Eversource	[A]	-1.56%	
Alberta	Fortis Alberta	[B]	0.30%	2.70%
Ontario	Hydro One	[C]	0.45%	2.19%

Notes:

In this table, a negative figure in the X-factor column represents a revenue increase. A positive figure in the K-factor column represents a revenue increase.

[A]: The Eversource decision does not indicate the likely revenue requirement of the Grid Modernization capital tracker. However, the tracker authorizes $133m over three years, equivalent to 1.4% of rate base per year.

[B]: K-factor estimated annual increase for 2019 through 2022.

[C]: K-factor averaged over four years, net of an additional 0.15% stretch factor.

• The adequacy of the ARA that is developed in this proceeding should be tested through financial analyses. The Companies will provide more detailed financial analyses as Phase 2 continues.

f. Recovery of the Adjusted Revenue Target

• The new MRP establishes the annual adjusted "target level" revenue allowed for recovery from customers each year, starting with the base target revenue generated by the revenue requirement approved in the base rate case, and with annual adjustments calculated by application of the revenue adjustment formula. Once the annual revenue target is set by operation of the revenue adjustment formula, the revenue target is recovered by operation of the RBA.

8. Consumer Dividend

a. Commission Guidance

The Consumer Dividend Factor is a "stretch factor" or reduction in allowed revenues.

b. General Considerations

• The inclusion of a stretch factor is generally justified on the grounds that operation under an incentive plan should increase efficiency. PEG reported that the average stretch factor in current North American MRPs is about 0.21%.

• A stretch factor can be used to adjust the initial rates, in lieu of inclusion of a stretch factor in the annual adjustment formula. For example, four years of 0.20% stretch factors could be replaced with a 0.75% stretch factor applicable to initial rates.

• Any Consumer Dividend must account for and not double count existing Company commitments and obligations.

• One of the fundamental principles of PBR is that customers share in the benefits of incentive regulation. These benefits may occur contemporaneously during the operation of the plan (i.e., ex ante benefits) or after the fact (i.e., ex post benefits). Ex ante benefits would include slower rate escalation through inclusion of a customer dividend or stretch factor in the escalation formula, and sharing the fruits of more efficient firm behavior through earnings sharing. Ex post benefits would include consumers reaping the fruits of more efficient firm behavior through rebasing of rates at the time the plan is reviewed.

• While PBR can be expected to lead to increased productivity growth, other factors may be changing at the same time that can be expected to reduce the magnitude of the stretch factor or nullify the stretch factor altogether. These other considerations include, but are not limited to: (1) negative TFP growth trends in the industry; and (2) increased capital expenditure requirements over the PBR term. In addition, if the previous period incorporated incentives, the strengthening of the incentives in modifying the MYPR may not be significant.

• The Companies have been operating under a relatively stringent revenue cap since the RAM Cap was adopted in 2015, and have not been able to earn their authorized returns since the imposition of the RAM Cap. The imposition of the RAM Cap primarily impacted Hawaiian Electric, which was also negatively impacted by the return to the lag in implementing the RAM adjustment in 2017.

c. Companies' Proposal

•If a Consumer Dividend is to be adopted, the Companies conditionally propose to include a Consumer Dividend Factor of 0.22% in the ARA Formula, which is the average stretch factor in current North American MRPs.

• The Companies' position, however, is that another Consumer Dividend is not warranted if and to the extent that a Customer Benefit Adjustment is made to the revenue requirement is setting base rates.

• Any Consumer Dividend must account for and not double count existing Company commitments and obligations, such as the existing Customer Benefit revenue reductions (roughly $11 million per year) established in the Hawaiian Electric 2017 test year rate case[12] and (roughly $450,000 per year) established in the Maui Electric 2018 test year rate case, and the $246 million in net benefits to be delivered to customers over 12 years associated with the new ERP/EAM system (with respect to which there is no shared savings incentive – 100% of the net savings are passed on to customers).

9. MPIR

a. Commission Guidance

• "The commission will preserve a mechanism for interim cost recovery for exceptional projects, to the extent that it may not be feasible to appropriately provide cost recovery for all such investments during the MRP exclusively through the ARA. At this time, the commission envisions that extraordinary relief for eligible projects will continue to be governed according to the MPIR Guidelines; however, the commission may consider revisions to the MPIR Guidelines in Phase 2, in order to remain consistent with the principles, goals, and outcomes of the PBR framework described herein, as well as the specific PBR Mechanisms under consideration." D&O 36326 at 10.

• "At this time, the commission envisions that MPIR relief will still be governed according to the MPIR Guidelines; however, it may be necessary to consider revisions to the MPIR Guidelines in Phase 2, in light of the PBR framework's Principles, Goals, and Outcomes, as well as the other PBR Revenue Adjustment Mechanisms and Performance Mechanisms under consideration. This also presents an opportunity to address capital bias that may be perpetuated through the current MPIR adjustment mechanism and explore how the MPIR may be used to address incentives regarding capital expenditures and operational expenditures." D&O 36326 at 34-35.

• "[T]he commission clarifies that during Phase 2, the Parties should consider relief provided under the MPIR adjustment mechanism as distinct from potential relief under the 'Z-Factor' component of the MRP indexed revenue formula. 'Z-Factor' events are intended to address

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[12] The final revenue requirement in Hawaiian Electric's 2017 test year rate case included two customer benefit adjustments totaling $11 million (including revenue taxes) or $10 million (before including revenue taxes). The adjustments included a $6,000,000 adjustment (grossed up from $5,467,000 for revenue taxes) ("Customer Benefit Adjustment#1") to return the full effect of the benefits related to the Net Pension Regulatory Asset Reduction, and a general $5 million revenue requirement reduction (grossed up from $4,556,000 for revenue taxes) ("Customer Benefit Adjustment #2") to be reflected in the Company's Results of Operations as a single line item that reduces operation and maintenance expenses. With respect to the first adjustment, (1) the total amount necessary to return to customers the full effect of the benefits related to the Net Pension Regulatory Asset Reduction will be $25,395,000; (2) a $5,467,000 Customer Benefit Adjustment per year is reflected in the Company's Results of Operations as a single line item that reduces operation and maintenance expenses (this amount totals $6 million when grossed up for revenue taxes) and is reflected in base rates, (3) the Customer Benefit Adjustment will remain in place until rates approved in the Company's next rate case go into effect; (4) any balance remaining when rates for the Company's next rate case go into effect (2020 test year rate case) will be reflected as a Customer Benefit Adjustment in the Company's next rate case in the same fashion as in this rate case (i.e., a single line item adjustment that reduces operation and maintenance expense). There is no carry over effect with respect to the second adjustment.

unforeseen events and are considered in determining the amount of allowed revenue in accordance with the ARA formula, whereas the MPIR Guidelines are used to prospectively seek relief for planned 'eligible projects' in addition to revenue determined by the indexed revenue formula." D&O 36326 at 35.

b. Current MPIR Mechanism

MPIR Guidelines

• The Hawaiian Electric Companies are currently able to request the recovery of Major Projects between rate cases through the MPIR mechanism. Order No. 32735 in Docket No. 2013-0141 defined "Major Projects" or "Major Capital Projects" as all projects subject to review and approval under the Commission's General Order No. 7. Rule 2.3.g.2. of General Order No. 7, as modified by Decision and Order No. 21002 in Docket No. 03-0257, requires electric utilities to submit to the Commission for review and approval any project with capital costs, net of customer contributions, in excess of $2.5 million. "Baseline projects" are capital projects that have capital costs, net of customer contributions, that are $2.5 million or less and are not subject to the General Order No. 7 review and approval process.

• Although Major Projects normally make up a smaller share of the construction budget than baseline projects, Major Projects can have very large capital investments that, if not timely recovered, would have a significant negative impact on the Companies' financials and on their ability to pursue other initiatives during the rate plan period. For example, the Schofield Generating Station for which the Commission granted MPIR recovery in Docket No. 2017-0213 has an estimated final capital cost of $147 million.[13] The cost recovery for the capital cost of the West Loch PV project, which is pending a decision on MPIR recovery in Docket No. 2016-0342, is capped at $62.4 million.[14]

• On April 27, 2017, the Commission issued Order No. 34514, which established the MPIR mechanism and the associated MPIR Guidelines in Attachment A to the order, and left the REIP Framework unchanged.[15] As the MPIR Guidelines replaced the provisions of recovery of Major Projects in Order No. 32734, the Commission stated "accordingly, recovery of revenues for costs of Major Projects placed in service between general rate cases will be through the MPIR adjustment mechanism" but also that "the HECO Companies may request interim recovery of revenues for projects that are not Eligible Projects as defined in the Guidelines through other means, including, for qualifying projects, the REIP." Order No. 34514, Docket No. 2013-0141, at 105-06 (emphasis added).

• The MPIR Guidelines state that the projects and costs that may be eligible for recovery through the MPIR adjustment mechanism are Major Projects subject to review and approval in

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[13] 2018 Fourth Quarter Capital Project Status Report filed on February 28, 2019, Attachment 2 at 1.
[14] Hawaiian Electric Company, Inc.'s Reply Statement of Position, filed on November 6, 2017 Docket No. 2016-0342 at 5.
[15] The Companies also recommend the continuation of the REIP mechanism to ensure the continuation of a means to support the implementation and recovery of renewable infrastructure projects, as originally contemplated by the Commission.

accordance with the applicable provisions of General Order No. 7, including but not restricted to certain illustrative examples, subject to the Commission's approval in accordance with these guidelines.[16] The illustrative examples include:

- Infrastructure that is necessary to connect renewable energy projects
- Projects that make it possible to accept more renewable energy
- Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use
- Projects in approved or accepted plans, initiatives, and programs
- Utility scale generation
- Grid modernization projects

• Exhibit "B" provides examples of some of the types of projects and project costs that should be eligible for recovery under the current MPIR guidelines.

• The Companies bear the burden of proof that all project costs proposed for MPIR treatment are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments.[17]

• The recovery of revenues for costs of Major Projects placed in service between general rate cases is through the MPIR adjustment mechanism, but the Companies may request interim recovery of revenues for projects that are not Eligible Projects as defined in the Guidelines through other means, including, for qualifying projects, the REIP.

MPIR Project Approval Process

• Major projects recovered through the MPIR mechanism must be pre-approved. The current review process has two layers and is very rigorous. First, one of the eligibility requirements for MPIR recovery is that the project must be a major project subject to review and approval in accordance with General Order No. 7. As a result, the Company must obtain Commission approval to commit expenditures for any project in excess of $2.5 million (i.e., a major project), in accordance with General Order No. 7, Rule 2.3.g.2. The Commission and the Consumer Advocate review extensively the need and estimated cost of the project before the Commission acts on the G.O. 7 application.

[16] Order No. 34514, Docket No. 2013-0141, Attachment A at 3-4.
[17] Order No. 34514, Docket No. 2013-0141, Attachment A at 6.

• The Company must also obtain approval in accordance with the MPIR Guidelines to recover the project costs through the MPIR mechanism. The MPIR Guidelines have a separate set of requirements, including the submission of a detailed business case study that should cover all aspects of the planned investments and activities – e.g., reasonably document and quantify the cost/benefit characteristics of the investments and activities and clearly outline how the project will advance transformational efforts with appropriate quantifications.[18]

Eligible Costs

• The Commission (1) has allowed recovery for Schofield Generation Station ("SGS") capital costs, and SGS O&M costs (after a business case filing); (2) has announced its intention to allow recovery for West Loch PV Project capital and O&M costs; and has allowed recovery for Grid Modernization Strategy - Phase 1 Implementation capital and deferred costs. The Hawaiian Electric SGS recovery amount for 2019 is $18,051,000 (not including revenue taxes). See Exhibit "B".

• Eligible costs should include deferred expenses to make expense solutions equivalent to capital projects. For example, there may be upfront or implementation costs (e.g., software development costs) that are required for the expense solution. If these costs are not eligible for MPIR recovery, there would be an incentive to select the capital alternative since certain upfront costs for a capital project can be capitalized and recovered.

• The specific inclusion of deferred costs and net O&M expenses as recoverable through the MPIR mechanism in the MPIR Guidelines would put capital costs and deferred and net O&M expenses on an equal footing for recovery and would facilitate the removal any bias of recovery of capital costs over deferred and O&M expenses in this mechanism. Since the MPIR Guidelines require separate approval for MPIR recovery of each project, the Commission will have the ability to approve or reject recovery of deferred costs or net O&M expenses, given the specifics of the project under review.

c. Role of Capital Project Cost Recovery Mechanisms[19]

• A PBR plan in which base revenues are adjusted by I – X, where X is generic rather than utility-specific, will typically have other mechanisms for collecting additional revenues, reflecting various items that are not "captured" within the I – X revenue adjustment. Terms used to describe these additional revenues include Y-factor, Z-factor and K-factor. There are likely to be differences in how the terms are used across jurisdictions and proceedings.

• Y-factor and Z-factor cover items that are added to the utility's costs for reasons that are nothing to do with the utility management ("outside management control"). The distinction between Y-factor and Z-factor is that Y-factor covers a defined list of items that, when the plan is designed, are already anticipated to need Y-factor treatment. The items are known, but the costs that will be incurred are not. Z-factor is more of a catch-all that permits the utility to bring forward applications, during the plan term, for cost recovery for "new" items that were not

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[18] MPIR Guidelines, pages 3-7.
[19] See Exhibit D, *Modifying the PBR Framework in Hawai'i.*

anticipated when the plan was designed and the list of items covered by Y-factor was developed. Examples of items included within Y-factor are franchise fees and local taxes.

• K-factors cover expenditures that are not covered by I – X. Usually, but not always, the K-factor covers capital expenditures rather than opex, and usually, but not always, K-factor is for specific projects or programs.

• Most MYRPs in the United States have utility-specific annual revenue adjustments. All electric distribution and transmission utilities in Australia and Great Britain have MYRPs with ARAs that are utility-specific. In Canada there are MYRPs in place in British Columbia, Alberta and Ontario that use external benchmarks usually for O&M but have utility-specific mechanisms for capital.[20]

d. Companies' Proposal

• The Companies propose the following clarifications and/or modifications for the MPIR mechanism:

- Clarify that major projects for equipment or facilities for new developments or unserved areas or to serve growth in an area would be eligible for MPIR recovery.
- Clarify the MPIR Guidelines, as noted above, to explicitly allow recovery of deferred costs and other expenses of a major project or program.[21] This would address capital bias concerns with the MPIR mechanism.
- Allow the inclusion of the full investment amount in the MPIR rate base for recovery in the year the project goes into service.

• Details regarding the Companies' MPIR proposal are included in Exhibit "C".

• Order No. 34514 states that the Commission intended the MPIR to have a broader scope of eligible projects and specific purposes than the Joint Proposed REIP Framework.[22] Therefore, it leaves in question what kinds of projects would be eligible for MPIR recovery that would not have been eligible under the Joint Proposed REIP Framework. It appears that these projects could be new (as opposed to replacement, relocated or restored) facilities, such as substations, transmission lines and structures, and distribution facilities in new developments. Arguably,

[20] Fortis BC is an exception as it indexes historical O&M expenses and historical capital expenses rather than revenues. The indexed O&M and capex are applied to opening rate base to calculate revenue requirements in each year of the plan. It also includes flow-through treatment for larger capital projects (projects over $20m)

[21] The Consumer Advocate suggested modifications to explicitly clarify that the MPIR adjustment mechanism may be used to recover both capitalized and expenses costs, but may not be used to recover "routine replacements of existing plant assets or expenses that would have been incurred but for the Major Project [.]" See CA SOP at 32.

[22] Order No. 34514, Docket No. 2013-0141, at 102. On June 15, 2015, the Companies and the Consumer Advocate filed their *Joint Proposed Modified REIP Framework/Standards and Guidelines* ("Joint Proposed REIP Framework"), which proposed to update and broaden the application of the REIP Framework approved in Docket No. 2007-0416.

these would not be "business-as-usual investments" since they would be serving areas of growth or unserved areas, as opposed to replacing facilities that are already serving customers. Recovery of new service facilities through the MPIR would be consistent with the concepts articulated in Order Nos. 32735 and 34514 and were not explicitly excluded from eligibility in the MPIR Guidelines. Confirmation of projects that would be eligible for MPIR recovery would be necessary to properly design a MYRP.

• Although the Companies may have agreed otherwise to settle a proceeding, they have always maintained that proper ratemaking should match the accrual of revenues with the timing of the incurrence of costs. This means that if a rate period reflects costs beginning on January 1 for a calendar year, the accrual of revenues <u>must</u> also begin on January 1 for the Companies to fully recover their costs. For MPIR recovery, this means that if a project goes into service in a particular month, the recovery of the return on the project investment must also be accrued at the time of the in-service date and must be based on the full investment amount of the project (since the full amount, not one-half, is actually incurred at that time) to reflect the correct carrying cost of the investment.[23] Otherwise, there will be a shortfall in recovery – a shortfall that would be large for a big project and one that the utility would never be able to recover. This constitutes a loss in recovery, not a lag. Without the ability to fully recover their costs, the Companies will not be able to earn their authorized rates of return.

e. General Considerations

• Using an (I – X – Consumer Dividend) formula based on a sample of electric utilities would not capture special conditions and circumstances of the Companies (e.g., accelerated integration of renewables, grid modernization, high cost of goods and services, isolated island grids, lack of scale, etc.).

• The RAM Cap implemented in 2015, and the reversion to a June 1st accrual in 2017 of the RAM increase for Hawaiian Electric, have made it difficult for the Companies to earn their authorized returns (even with the general rate case increases that have been authorized).

• An analysis by the Brattle Group showed that target revenues increased over the 2012–2016 period on average by 3.43%. In order for HECO to have achieved the authorized ROE in each year, the required increase would have been 4.35%.[24]

• To achieve renewable energy and transformation goals, the Companies have to expend dollars. If the Companies' Annual Revenue Adjustment is constrained too much, the result could be disincentives to incur the very costs that will enable attainment of the reduction in the fuel and purchased power expense component of the revenue requirements.

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[23] The only way for MPIR projects on average to obtain full recovery using an average rate base in the initial year is to allow the accrual of MPIR revenues for the full twelve months of the initial year, regardless of the in-service date of the project in that year.
[24] Workpapers for the March 2019 Brattle Group Report, dated April 4, 2019, included in Exhibit B to the Companies' RSOP.

• If the desire is to provide incentives for the Companies to do more to support transformational goals and outcomes, and at a faster pace, and at the same time have longer periods between rate cases, those incentives should include opportunities for the Companies to recover the associated costs; not make recovery more difficult than it is today by imposing more restrictions and requirements on the recovery mechanisms. Constraining the ability to recover prudently incurred costs will have the opposite effect, making it more difficult to initiate, implement and finance desired programs and slowing progress towards modernizing the grid and achieving the transformational goals and outcomes desired by Parties in this proceeding.

• The MPIR will need to be aligned with the design of the MPR. The different elements of the MYRP will have to be balanced to maximize the potential for achieving the various goals and outcomes established in this proceeding, while also enabling the utility to maintain its financial integrity (which is essential to meeting its basic obligation to provide safe, secure, reliable and resilient electric service to its customers and supporting the achievement of the PBR goals and outcomes)

• Whether the MPIR mechanism will provide sufficient revenues will depend on the amount of revenues provided by the Annual Revenue Adjustment. If not, the scope of the MPIR mechanism may need to be broadened, or there may need another mechanism (such as the REIP Surcharge) to close the gap.

• The Companies plan to run their financial model to determine the needed scope of MPIR, given the parameters of the (I - X - CD) revenue adjustment.

• Generally, the Companies agree that it is difficult to include recovery of "lumpy" major capital projects in an indexed revenue cap rate plan.[25] Exhibit C to its RSOP included a graph showing the historical major and baseline net plant additions for Hawaiian Electric for the period 2014 through 2018 and the projected net plant additions from 2019-2021. This graph shows the variability of major net plant additions compared to baseline plant additions from year to year.

• The major project net plant additions have been relatively small for the 2014-2017 period. However, from 2018, the proportion of major plant additions increases beginning with the Schofield generating station project, which is the first major project to receive approval for MPIR recovery. The annualized adjustment to target revenues (with revenue taxes) for this project for 2019 is $19,810,800,[26] based on a capital cost of $141,570,000 and annual O&M expenses of $2,087,000.[27]

• The Staff Proposal suggests that: "MRP and IGP cycles will need to be aligned, such that an approved or accepted IGP plan informs the setting of base rates or target revenues for the subsequent MRP control period, which should improve regulatory efficiency."[28] Most of the

[25] Staff Proposal, page 30.
[26] Transmittal 19-01, Attachments 1-2 filed on February 7, 2019, and Schedules B1 and L filed on March 29, 2019.
[27] Transmittal 19-01, filed on March 29, 2019, Schedule L1, page 1.
[28] Staff Proposal, Appendix D at 3.

parties emphasized the importance of "harmonizing" the IGP process with PBR, but did not explain how this should be done. RSOP at 39-44.

• For the IGP and IGP process to be harmonized with the PBR plan, there should be a linkage between an approved IGP Plan and the revenues received during the Control Period. However, that is unlikely to be the case if the ARA escalator becomes even lower than the current inflation-indexed RAM Cap, and the MPIR mechanism becomes more, not less, restrictive. Current rates and base rates set prior to the control period do **not** include the revenue requirements for the future plant that would be added during the control period. The revenue requirements increases (including the return on the rate base increases and higher depreciation expenses) arising out of the future plant that is added during the control period have to be accounted for by the ARA and MPIR mechanism.

> • The MPIR would account for the revenue requirements increases resulting from **qualified** major plant additions. The general escalator would have to account for the revenue requirements increases resulting from baseline plant additions and non-qualified major plant additions. A general escalator limited to inflation less a productivity offset and a consumer dividend offset would not do that.
>
> • The approved or accepted IGP plan would help inform the Commission as to whether the MPIR mechanism should be authorized for specific major projects, but there is also a separate project pre-approval requirement imbedded in General Order No. 7 for major projects, and in the MPIR guidelines.

10. Z-factor

a. Commission Guidance

• A Z-factor is applied (ex post) to account for exceptional circumstances not in the utility's direct control (e.g., tax law changes).

b. Companies' Proposal

• The Companies propose to include a Z-factor in the ARA formula to account for exceptional circumstances not in the utility's direct control (e.g., tax law changes). The detailed proposal includes Z-factor Eligibility Criteria, generic and specific examples of Z-factor events, annual Z-factor Materiality Thresholds, and Z-factor Filings details.

Z-factors

• Z-factors are exogenous events, largely uncontrollable by management, having a material and disproportionate impact on the Company. A Company's operating environment and its costs change continuously, often due to unexpected events. The unexpected event causing the cost must be exogenous to the Company. The event must occur after the test year in which base rates are set, so that the costs and event are not reflected in current effective rates. The Company must incur the cost reasonably. The cost impact must be measurable.

• There are two types of Z-factor Costs that are beyond the Company's control. The first type of Z-factor Costs are those costs that are nonrecurring and result from a *force majeure* event, which, by way of example, shall include events such as riot, terrorism, sabotage, war, strike or labor disturbance (other than by the utility's bargaining units) or acts of God. The second type of Mandated Costs are recurring or nonrecurring in nature and include ongoing costs that result from accounting changes, or federal or state legislative, regulatory or tax changes. This second type of Z-factor Cost includes either cost increases, decreases or changes in revenue caused by the triggering Z-factor events.

• Z-factor Events generally will impact the O&M Expense component of Target Revenue, but may also impact the Return on Rate Base Component and the Depreciation Component. The Return on Rate Base revenue requirement is based on the margin requirement for capital related costs determined under traditional cost of service methodology divided by the associated capital costs. Such costs are: return on weighted average rate base (using the current authorized rate of return), taxes on that return, depreciation expense at the system average rate, plus authorized revenue taxes.

Z-factor Eligibility Criteria:

(1) The costs (savings) must be attributable to events outside the control of a prudently operated utility;

(2) The costs (savings) must be related to the exogenous event and outside the base upon which the rates were originally derived;

(3) The cost impact of the event must be clearly outside of the base upon which current effective rates were derived.

(4) The costs must be prudently incurred; and

(5) The costs (or savings) related to each exogenous event must exceed the defined Materiality Threshold.

Examples of Z-factor events include, but are not limited to:

(1) Accounting rule changes promulgated by the Financial Accounting Standards Board (FASB), the Securities and Exchange Commission (SEC) or the Commission

(2) Changes in State, federal or county (or any local jurisdiction having taxing authority) tax laws or regulations, or changes in the interpretations of any such laws or regulations;

(3) Regulatory, legislative, or judicial mandates or actions impacting the utility

(4) Major unplanned maintenance costs or investments, such as those incurred due to unexpected major maintenance and major repairs to Company-owned power plants

(5) Catastrophic events, including but not limited to tsunami, wild fires, volcanic eruptions and lava flows, earthquakes, floods, and landslides

(6) *Force majeure* event, which, by way of example, shall include events such as riot, terrorism, sabotage, war, strike or labor disturbance (other than by the utility's bargaining units) or acts of God other than storms

(7) Changes in revenue requirements due to Commission decisions (e.g., depreciation rate changes)

(8) Major storms

(9) Environmental remediation events

Z-factor Materiality Thresholds:

• The Materiality Threshold is based on the revenue requirements arising out of the costs incurred or to be incurred due the Z-factor event during an Adjustment Year. In the case of Major Storms, the costs that are compared to the threshold and that are eligible for recovery through the Z-factor are limited to Major Storm costs in excess of the Major Storm threshold amount set in the last Base Rate Case (i.e., the normalized major storm costs included in the revenue requirement). In the case of environmental remediation events, the costs that are compared to the threshold and that are eligible for recovery through the Z-factor are limited to environmental remediation event costs in excess of the environmental remediation event threshold amount set in the last Base Rate Case (i.e., the normalized environmental remediation costs included in the revenue requirement).

• The Materiality Threshold is applicable to each separate Z-factor event, and applies to the revenue requirement impact of the event during a year.

• The Companies propose annual Materiality Thresholds of $4 million per event for Hawaiian Electric, and $1 million per event for Hawaii Electric Light and Maui Electric.

Z-factor Adjustments

• Z-factor adjustments will be expressed as a change in revenue requirement. The calculated change in revenue requirement may be based on the Base Year results of operations, as adjusted for the impact of the event (for example in the case of a change in tax laws), and the application of the ARA-factors in subsequent years.

• Z-factor adjustments may be positive or negative, depending on the nature of the event. For example, a change in tax laws may result in a reduction in income taxes, and a net reduction in revenue requirement.

• For Z-factor events occurring in the last year of the Control Period, the Commission may allow the costs to be deferred, to accrue interest, and to be amortized in the next general rate case.

• When a nonrecurring Z-factor Cost event occurs or upon the occurrence of a recurring Z-factor Cost, the Company may defer on its books of account (without any presumption of the ratemaking treatment) the Z-factor Cost for future recovery in the next annual Z Factor adjustment.

Z-factor Filings

• The Company first notifies the Commission about the existence of a potential Z-factor event or cost. (The Company then begins recording the additional costs or cost savings incurred as a result of the Z-factor event in a deferred account.) In the next step, the Company seeks authorization to recover the costs of the Z-factor event, and includes documentation demonstrating that the proposed Z-factor exceeds or will exceed the threshold amount, and the basis for Z-factor treatment of the event. The Commission, on its own motion or upon petition by the Division of Consumer Advocacy, may require the submission of a Z-factor adjustment filing by the Company.

• Z-factor filings may be based on future cost increases or savings in the Adjustment Year, where the cost increases are known and measurable (for example, in the case of a change in the tax laws, where the revenue requirement impact may be calculated by reflecting the tax law changes in the Base Rate Case results of operations), or may be based on costs incurred during the year prior to the Adjustment Year.

• In the case of a nonrecurring Z-factor Cost event that results in cost impacts in more than one year, a Z-factor adjustment may be made for each year in which the Z-factor Cost exceeds the Materiality Threshold. For example, if a catastrophic event occurs in AY1 that qualifies as a nonrecurring Z-factor event, and the Z-factor Cost arising out the event in AY1 exceeds the threshold, then a Z-factor adjustment may be made in AY2. If the Z-factor Cost arising out the event in AY2 also exceeds the threshold, then a Z-factor adjustment may also be made in AY2.

Z-factor Examples

• One example is the Tax Cuts and Jobs Act ("Tax Reform Act" or "Tax Act")[29] that was signed into law on December 22, 2017. The Tax Reform Act had numerous impacts on the Companies' revenue requirements, which were captured for the benefit of customers (effective back to the effective date of the tax law changes) in the Companies' 2017-2019 test year rate cases. See, e.g., Parties' Stipulated Settlement on Remaining Issues, dated and filed March 5, 2018, in Docket No. 2016-0328, Hawaiian Electric's 2017 Test Year Rate Case (Exhibit 1 at 21-22).

11. Cost of Capital Adjustment Mechanism

a. Companies' Proposal

[29] Public Law 115-97 commonly known as the "Tax Cuts and Jobs Act."

• The Companies propose that the California method of setting the cost of capital in a separate proceeding (rather than in the Companies' rate cases), and adjusting the cost of capital revenue requirements in between such separate proceedings, be adopted in Hawaii.

• Details regarding California's Annual Cost of Capital Adjustment Mechanism are included in Exhibit "E".

b. Cost of Capital Adjustment Mechanism Details

• The Companies propose to include a Cost of Capital ("COC") Factor in the target revenue adjustment formula, either as (a) a separate COC Factor, or (b) as a component of the Z-factor.

• The COC Factor, which could be negative or positive, would be determined using a new Cost of Capital Adjustment Mechanism ("COCAM"). The COCAM would be used to periodically determine the COC (i.e., the rate of return on rate base) used in determining the revenue requirement in general rate cases, and for other purposes, including but not limited to determining the revenue requirement impact of capital projects included in the MPIR or in the Z-factor.

• The base COC would be re-determined in a separate (i.e., not in a general rate case proceeding) contested case proceeding held every five (5) years. Public hearings would be held in accordance with HRS §269-16(b) and HRS §269-12(c). The first COC proceeding would be based on a 2023 test year. The second COC proceeding would be based on a 2028 test year, unless the Commission sets a different test year in the 2023 test year proceeding. The Companies would file an application to reset the base COC, with written testimonies and exhibits by April 30^{th} of the prior year (i.e., by April 30, 2022 for the first proceeding).

• A utility retains the right to file a new COC Application outside the COCAM process if there is a catastrophic or extraordinary event of change in operations that has a substantial impact on its cost of capital or capital structure. For example, the Companies (under the guidance of the Commission) have initiated one of the largest renewable energy and integrated procurements ever undertaken by a U.S. utility, seeking to add up to 900 MW of renewable energy, more than 500 GWh of storage and grid services. This is in addition to the 247 MW of solar energy and approximately one GWh of storage for which the Commission approved contracts earlier in 2019, and the more than 150 MW of utility-scale renewables are currently under construction, including approximately130 MW of utility-scale solar expected to come online on Oahu this year. This magnitude of purchased power obligation (and resulting implicit debt) could have a material impact on the Companies' capital structures after their current rate cases.

• The new base COC would be used to adjust the rate of return on rate base component of the target revenues used in the Annual Revenue Adjustment. For adjustment years for which there is not a COC test year, if there is a change in the interest rate benchmark of 100 basis points (the "Deadband") or more, the COC would be adjusted to reflect (a) the calculated change in the rate of return on common equity ("ROE") used in determining the base COC, and (b) the actual changes in the cost of long-term debt, short-term debt, hybrid securities, and preferred stock.

The capital structure ratios used in the cost of capital calculation would only be reset in a COC proceeding.

• The base interest rate (the "Benchmark") would be the average interest rate for Moody's Baa-rated electric utility long-term bonds for the COC test year. The calculated change in the ROE would be 50% of the basis point change in the interest rate Benchmark from the COC test year to the review year.

• The Adjustment to target revenue is made in the next year (i.e., the adjustment year), and accrues to the beginning of the adjustment year. The first potential adjustment is in 2022.

• Since the first base COC proceeding would not be filed until 2023, the base COC would initially be set in the current general rate cases (i.e., rate cases using (a) a 2019 test year for Hawaii Electric Light, (b) a 2020 test year for Hawaiian Electric, and (c) a 2021 test year for Maui Electric)). The bench mark interest rates would be the average interest rate for Moody's Baa-rated electric utility long-term bonds (a) for 2019 for Hawaii Electric Light, (b) for 2020 for Hawaiian Electric, and (c) for 2021 for Maui Electric.

c. Cost of Capital Adjustment Mechanism Implementation Details

• The utility monitors the utility bond index for the period October 1 (of the previous year) to September 30 (of the current year) and calculates the 12-month average for that period, and compares it to the Benchmark.

• Data Source for utility bond interest rates - historical Moody's monthly utility bond interest rate averages, which are available through subscription services from Moody's.

• In any year where the difference between (1) the 12-month October through September average Moody's utility bond interest rates and (2) the Benchmark, exceeds the Deadband, an automatic ROE adjustment is triggered effective on January 1 of the next year, which includes:

  • The 12-month October through September utility bond interest rate average that triggered the ROE adjustment becomes the new Benchmark.

  • The ROE adjustment is calculated, which is equal to 50% of the difference between the old Benchmark and new Benchmark. The ROE adjustment is applied to the total basis point difference between the old and new interest rate benchmark. The adjustment ratio reflects the change in interest rates that should be reflected in the return on equity
.

  • For example, if the difference between the 12-month average utility bond interest rates and the Benchmark is 1.2% and falls outside of the Deadband, then the ROE adjustment is 0.6% (50% of 1.2% is 0.6%). Then, if the currently authorized ROE is 9.5%, the new ROE will be 9.5% + 0.6%, or 10.1%.

  • Long-term debt, short-term debt, and preferred stock costs are updated to reflect average costs for that year, including embedded costs at the beginning of the year and

forecasted costs at the end of the year (including the impact of scheduled issuances and retirements).

• In October of the year where an ROE Adjustment is triggered, the change is implemented as follows:

• Recalculate the ROE and long-term debt, short-term debt, hybrid security and preferred stock costs: New ROE = Currently authorized ROE + ½ (new Benchmark - current Benchmark)

• Recalculate the total revenue requirement (update results of operations model) using these new costs.

• Submit a tariff transmittal to the Commission, presenting the changes to ROE, costs of long-term debt and preferred stock, and change in revenue requirements effective on January 1st.

12. ESM

a. Commission Guidance

• "In order to maintain a reasonable range of utility earnings, Phase 2 will prioritize examination of an ESM that provides both 'upside' and 'downside' sharing of earnings between the utility and customers when earnings fall outside a commission-approved non-adjustment range or 'deadband', though not necessarily symmetrical amounts. The quantification of earnings subject to adjustment by the ESM will be comprehensive, including the contributions of target revenues, performance incentive revenues, cost trackers, and other components of overall utility revenues." D&O 36326 at 9, 32.

b. General Considerations

• Earnings sharing mechanisms are often viewed by regulators as providing a backstop or safety net to both regulated firms (if earnings are "too low") and consumers (if earnings are "too high"), which can lessen the risks to either or both firms and consumers. However, it is also recognized that such mechanisms require customers to bear greater risk because of the potential for rate adjustments if earnings are "too low"; and reduce incentives for efficiency by the utility subject to PBR because their ability to reap the benefit of efficiency gains is capped.

• The strength of PBR incentives depends on the form of PBR and how much of the cost savings the firm is allowed to retain. For example, under an earnings sharing mechanism, the firm is allowed to retain earnings above the authorized return on equity ("ROE") up to a certain point - e.g., 200 basis points above authorized ROE - after which, excess earnings are refunded to customers. Consequently, the firm has a strong profit motive to become more efficient up to the full sharing point. Above that point, the PBR plan operates much like traditional COS regulation. Thus, theorists and some parties view ESMs (and Off-Ramps) as being contrary to PBR theory.

• Customers can share earnings in two ways. The Companies propose to include provisions for refunding the customers' share (or crediting it to the RBA balance). In the alternative, the customers' share of surplus earnings to be used to reduce the balances of regulatory assets or to fund special efforts.

• There is an existing asymmetric ESM that is part of the existing decoupling mechanism. If the existing ESM were restated as a symmetric ESM, the sharing bands would be as follows:

Band 1: First 100 basis points (i.e., 8.5%-9.5% & 9.5%-10.5%) – 25% share to customers

Band 2: Next 200 basis points (i.e., 6.5%-8.5% & 10.5%-12.5%) – 50% share to customers

Band 3: Greater than 300 basis points (i.e., less than 6.5% & more than 12.5%) – 90% share to customers

c. Companies' Proposal

• The Companies propose a symmetric ESM.

• The key elements are the dead bands, sharing bands and sharing percentages within each band.

• The illustrations of the bands in the Companies' proposal are based on an authorized ROE of 9.5% (i.e., 950 basis points). The bands would apply to the Companies authorized ROE as initially set in its base rate cases, and as adjusted from time-to-time through the COCAM.

• The Companies propose the following bands and sharing percentages:

Band 1: 200 basis points (i.e., + or – 100 basis points) – no sharing, SHs absorb or receive full amount

Band 2: 200-400 basis points (i.e., 7.5-8.5% & 10.5-11.5%) - share 25% customers/75% SHs in this band)

Band 3: 400-600 basis points (i.e., 6.5-7.5% & 11.5-12.5%) - share 50% customers/50% SHs in this band

Band 4: 600-800 basis points (i.e., 5.5-6.5% & 12.5-13.5%) - share 75% customers/25% SHs in this band

Band 5: greater than 800 basis points (i.e., less than 5.5% or greater than 13.5%) - no sharing, customers absorb or receive full amount

• In the alternative, the Companies propose more graduated bands and sharing percentages as follows:

Band 1: 300 basis points (i.e., + or – 150 basis points) – no sharing, shareholders ("SHs") absorb or receive full amount

Band 2: 300-600 basis points (i.e., 6.5-8% & 11-12.5%) - - share 50% customers/50% SHs in this band

Band 3: greater than 600 basis points (i.e., less than 6.5% or greater than 12.5%) - no sharing, customers absorb or receive full amount

• The rate of return on common equity ("ROE") used in the ESM would be determined on a ratemaking basis (which excludes costs disallowed in general rate cases) as it is under the existing ESM. The ROE will be calculated on a regulatory basis based on the same methodology used for the existing ESM calculation.

• The Companies also propose to include incentive credits and penalties in calculating the ratemaking ROE. (The Commission proposes to include incentive credits and penalties in calculating the ratemaking ROE.)

13. Off Ramps

a. Commission Guidance

• "Consideration shall be given to examining 'off-ramp' mechanisms to provide for review of approved PBR mechanisms, pursuant to specified exceptional circumstances or conditions." D&O 36326 at 10, 33.

b. General Considerations

• Off ramp mechanisms allow for MYRPs to be reconsidered if certain events occur during the plan. There is less need for an off ramp mechanism if the plan features an ESM, revenue decoupling, Z factor, or other measures that reduce risk.

• The qualifying events typically involve "extreme" ROEs, but may instead involve other considerations such as inflation or reliability or catastrophic events. Some plans include two ROE triggers, for example: (i) if a utility's ROE is 500 basis points above or below the allowed ROE in a single year and (ii) if a utility's ROE is 300 basis points above or below the allowed ROE during any two consecutive years.

• The rules for what happens following a qualifying off ramp event vary. A formal proceeding to reconsider plan terms may be mandatory or at the regulatory commission's discretion. Reconsideration may be limited to a revision of plan terms or include a new rate case.

• Alternatives to off ramps include re-openers, which involve reconsideration and adjustment of plan elements without terminating the plan, and mid-control period reviews.

c. Companies' Proposal

• The Companies propose to include an off ramp provision with two ROE triggers and a catastrophic events trigger.

• The Companies propose to include two ROE triggers: (i) if a utility's ROE is 500 basis points above or below the allowed ROE in a single year and (ii) if a utility's ROE is 300 basis points above or below the allowed ROE during any two consecutive years.

• If an off ramp trigger occurs (or if the Company can demonstrate to the Commission's satisfaction that a trigger is likely to occur), then the Commission by order on its own motion, or upon petition by the Company, will determine what the appropriate remedy is. Appropriate remedies may include, but are not limited to, having the Company file a general rate case application, and adjusting parts of the ARA formula pending the effective date of new rates set in the general rate case.

14. Revenue Neutral Rate Resetting During Control Period

a. Commission Guidance

• "Due to development of a MRP, as well as other revenue adjustment mechanisms under consideration, the commission recognizes that there will likely be a need to examine changes to the Companies' rate design structure during the MRP. Such rate design revisions are expected to be revenue neutral (i.e., not affecting the revenues set by the ARA) and will be addressed in a separate proceeding." D&O 36326 at 32.

• In D&O No. 36230, the Commission required the Companies to file an Advanced Rate Design Strategy within six months of the date of the D&O, as a condition of MPIR recovery for costs related to implementing the first phase ("Phase 1") of the Companies' Grid Modernization Strategy.[30]

b. General Considerations

• The current regulatory model establishes base and optional rates in conjunction with general rate cases. In considering longer periods between rate cases, consideration should be given to the way in which the revenue adjustment and decoupling mechanisms are implemented (i.e., the RBA and RAM) to ensure that the integrity of the rate designs established in the rate case are maintained between rate cases.

• In the rate case, customer, demand and energy rates are revised to reflect changes in the cost of service as well as to provide appropriate pricing signals to encourage customers to use electricity efficiently. As customer needs and interests are continuously changing, often in response to

[30] Re Application of Hawaiian Electric Companies for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, and Related Requests, Docket No. 2018-0141, Decision and Order No. 36230 ("D&O No. 36230"), filed March 25, 2019. D&O No. 36230 was clarified by Order No. 36334, filed May 27, 2019.

advances in technology and incentives induced by public policy, rate design should be flexible to provide customers with innovative choices on a timely basis.

• As shown in the memorandum entitled "PBR – Rate Design between Rate Cases", attached as Exhibit "F" to this proposal document, extending the period between rate cases to five years could cause distortions in the rate design established in a rate case, and could delay need changes in the rate design.

• Other jurisdictions avoid or at least reduce these difficulties either by adjusting rate structure in a proceeding separate from (and more frequent than) the rate case, or by recovering balancing account revenue in rate elements that go beyond the kWh charge or any other single component of rate design.

c. Companies' Proposal

• The Companies propose that the Commission, by order on its own motion, or upon petition by the Company for good cause shown, initiate a revenue neutral proceeding during the Control Period to reallocate revenues among customer classes, and/or redesign the rates within customer classes.

• The revenue neutral proceeding would not result in a general rate increase for the Company, because it would not result in a change in Target Revenues, but would be expected to result in rate increases or decreases for individual customers. The Commission would determine whether it would be appropriate to hold public hearings with respect to potential rate design changes in the proceeding.

15. Rebasing Rates at End of Control Period

a. Companies' Proposal

• The Companies recommend that, at the end of the initial control period, another set of rate cases or a consolidated rate case be used to reset base rates.

• The process for resetting base rates needs to be established at the outset. Uncertainty has the effect of weakening incentives that flow from the PBR plan. Therefore, it is preferable that the process for resetting base rates after the control period be set out with some precision at the outset of the PBR plan.

• Consolidating proceedings for the three Companies' rate cases would promote administrative efficiency within the regulatory framework. The Companies are developing details and issues for consideration on how rate case consolidation could work.

b. Rate Case Timing

• The Companies propose that the test year for a consolidated rate case be calendar year 2025, and the companies be permitted to file such a consolidated rate case as early as May 1, 2024 (based on a test year waiver).

16. Implementation Details

a. Implementation Date

• The new MRP would be put in place for Hawaiian Electric and Hawaii Electric Light such that the first adjusted revenue target would be effective January 1, 2021. The new MRP would be put in place for Maui Electric such that the first adjusted revenue target would be effective January 1, 2022.

• The Companies propose to have a two-step ARA process. On September 30 of the year preceding the adjustment year [Adjustment Year ("AY")-1], the Companies would file a Tariff Transmittal ARA for a change in rates which would be effective January 1 of the adjustment year, subject to Commission approval. On March 31 of the adjustment year, the Companies would file an ARA based on updated factors for a change in rates which would be effective on May 1 of the adjustment year (replacing the ARA rate that was effective from January 1), subject to Commission approval. Major Project Interim Recovery ("MPIR") filings would generally maintain their current status and be incorporated within the ARA filings. These proposed processes are described further below.

• The September 30 AY-1 ARA filing would support in a change in rates effective on January 1 of the adjustment year as follows:

- ARA based on target revenues from the latest rate case (adjusted through the latest ARA filing) adjusted by: I-X-customer dividend.
    - The escalation component would consist of:
        - I = Inflation Factor based on the consensus estimated annual change in the GDP-PI[31]
        - X = Productivity Factor determined by econometric modeling and approved by the Commission in this proceeding
        - Customer dividend = as approved by the Commission in this proceeding.
- Target revenues would further be adjusted by:
    - Z factor = adjustment in target revenues associated with any exogenous items, if known at the time. Z factors would include, but not be limited to, changes in tax laws or regulations and environmental assessments that are that are subject to annual Materiality Thresholds.

  The September 30 ARA transmittal filing would result in a change in target revenues effective January 1, AY.

[31] The GDP-PI escalation rate shall be the consensus projection published by the Blue Chip Economic Indicators (Aspen Publishing) each September (AY-1) for the adjustment year. In the event that the Blue Chip Economic Indicators forecast of the GDP-PI is not available, the Consumer Advocate and Company, with approval of the Commission, shall jointly select an alternative data source, or national economic index similar to GDP-PI, as appropriate.

- Collection or return of the accumulated RBA balance at August 31, AY-1. The accumulated RBA balance would include the following accrued balances:
    - The monthly revenue balancing entries to accrue revenues to match the monthly target revenue (target revenues would include any major project interim revenues "MPIR" approved for accrual)
    - Any other adjustments approved by the Commission to flow through RBA
- The rate change would also include the rewards/penalties from any known Performance Incentive Mechanism ("PIM") for AY-1

• Similar to the current annual decoupling filing process, the Companies propose to have informal discovery and discussions with the Consumer Advocate following the September 30 filing. The Consumer Advocate's statement of position would be due on October 30, AY-1 (30 days after tariff transmittal filing[32]). The Companies would request a Commission order approving a change in rates by December 30, AY-1 (but not less than one business day before the effective date), to enable implementation of the change in rates effective January 1, AY.

• The March 1, AY Tariff Transmittal filing would support a change in rates effective on May 1, AY which would include the following:

- Updated ARA based on updated Z-factors
    - Z factors would include, but not be limited to, changes in tax laws or regulations and environmental assessments that are subject to annual Materiality Thresholds.

  The updated ARA would result in a change in target revenues accrual effective January 1, AY.
- PIM award/penalty for AY-1 based on actual results for AY-1 and any other known PIMs as of the March 1, AY filing
- Earnings Sharing Mechanism for AY-1 based on actual results for AY-1.
- Collection or return of the accumulated RBA balance at January 31, AY. The accumulated RBA balance would include any MPIR adjustments to target revenues that had been approved and are embedded in the accrued balance.

• Similar to the AY-1 process described above and the current annual decoupling filing process, the Companies propose to have informal discovery and discussions with the Consumer Advocate following the March 1 filing. The Consumer Advocate's statement of position would be due on April 1, AY (30 days after tariff transmittal filing). The Companies would request a Commission order approving a change in rates by April 30, AY (but not less than one business day before the effective date), to enable implementation of the change in rates effective May 1, AY. The Companies propose that change in target revenues accrual begin January 1 of the adjustment year, superseding the target revenues which had accrued based on the September 30 filing.)

• The Companies' proposed modifications/clarifications to the MPIR mechanism notwithstanding, the MPIR process and schedules would remain largely unchanged. However, consideration should be given to slightly adjust the timing of the annual MPIR which is currently

[32] Same as Final D&O, Docket No. 2008-0274, filed on August 31, 2010, p. 129

scheduled for on or before February 28 to March 1 to be incorporated in the proposed March 1 ARA update Tariff Transmittal filing.

Proposal Summary

Filing Description	Filing Date	Change in Rates Date	Change in Target Effective ("Accrual Date"
Annual Revenue Adjustment • ARA (I-X-customer dividend) • Z factors • RBA balance as of Aug 31 (including any MPIR or other adjustments accrued in the RBA through the change in target rev) • Known PIM rewards/penalties	Sept 30, AY-1	Jan 1, AY	Jan 1, AY
ARA update • ARA with updated Z factors • RBA balance as of Jan 31 (including any MPIR or other adjustments accrued in the RBA through the change in target rev) • Actual PIM for AY-1 • Actual ESM for AY-1 MPIR annual filing	Mar 1, AY	May 1, AY	Jan 1, AY
MPIR (new project in service) [same as current process]	Month following in service	When next RBA change incorporates	Month following in service

D. COMPANIES' KEY CONSIDERATIONS

1. The Companies plan to fully consider the detailed proposals submitted by the other Parties, as well as any further guidance provided by the Commission in Phase 2, and to fully participate in the Phase 2 workshops planned by the Commission. The Commission has indicated that the Parties will have the opportunity to submit further refined proposals as Phase 2 proceeds (i.e., in January 2020 (Workshop C), in May 2020 (Workshop D), and in June 2020 (SOPs). The Companies reserve their rights to modify and refine their proposals as Phase 2 proceeds.

2. The Companies have considered MRPs submitted and approved in other jurisdictions, and the reports of their expert consultants, Pacific Economics Group Research LLC ("PEG") and The Brattle Group ("Brattle Group"). The MYRP positions taken by the Companies in this proceeding are supported by reports prepared by their expert consultants. Reports submitted in Phase 1 included: (a) Exhibit 1 to the Companies' Metrics Brief (filed January 4, 2019) was a report prepared by PEG) (M. Lowry, M. Makos) entitled *Regulatory Reform for the Hawaiian Electric Companies* (Jan. 2019) ("PEG Report"); (b) Exhibit 2 was a report prepared by The Brattle Group (T. Brown, W. Zarakas), entitled *Improving the PBR Framework in Hawai'i, Addressing the Risk of "Capex Bias"* (Jan. 2019) ("Brattle Group Report"); (c) PEG's comments in response to the Staff's MYRP positions and recommendations (provided by Dr. Mark Lowry and Mr. Matt Makos) ("PEG Response") were included in Exhibit B to the Companies' SOP; and (d) The Brattle Group comments in response to the Staff Report (provided by Dr. Toby Brown) were included in Exhibit C to the Companies' SOP.

3. The MRP details are extremely important, and the Companies' support for a particular change in the regulatory framework will depend on the details.[33]

4. It is broadly recognized that one size does not fit all.[34] Adjustments to the existing Framework must take into account Hawai'i's and the Companies' unique circumstances, rather than be based on a "cook book" approach. (The Hawaiian Electric Companies are not electric distribution utilities. The Hawaiian Electric Companies are vertically integrated electric utilities, with a strong mandate to acquire cost-effective clean energy resources, to integrate distributed energy resources, and to empower customer choice, and to take the steps necessary to accomplish these goals, including modernizing their grids.) Instead, "PBR is made up of several elements that can be applied in different ways and in different combinations, intended to strengthen utility performance."

5. PBR should encourage the acquisition of cost-effective renewable energy resources:

- The greatest customer benefit will come from modernizing the grid, increased customer engagement enabled by the modernized grid platform, and substitution of lower cost, clean renewable energy for higher cost fossil-fuel resources. The key to constraining or even reducing rates (in real dollar terms) is substituting lower cost renewable energy resources for fossil-fuel fired resources. These savings are passed through to customers as they are accrued through the ECRC and the PPAC, and are not retained by the Companies to pay for the costs incurred to achieve the benefit.

- The driver for the desire to change the RAM formula appears largely to be the desire to reduce rates. A key to reducing rates is substituting lower cost renewable energy resources for fossil-fuel fired resources. Changing the RAM formula in a way that makes it even more constrained (i.e., more conservative) than the existing RAM Cap could be counterproductive, as it could result in disincentives to incur the very costs that will enable attainment of the reduction in the fuel and purchased power expense component of the revenue requirements.[35]

- As a corollary, over-constraining the target revenue requirement (in the hopes of encouraging efficiencies) can result in disincentives to incur the very costs that will

[33] *See* Staff Proposal at 53 ("Implementation of PBR elements proposed herein depends upon determination of many crucial details that have not yet been identified and are subject to more focused and thorough examination in Phase 2.").

[34] "PBR is not a one-size-fits all construct designed uniformly wherever it is applied." Order No. 35411, issued April 18, 2018, in Docket No. 2018-0088, Instituting a Proceeding to Investigate Performance-Based Regulation ("Order No. 35411") at 14. *See also M. Lowry & T. Woolf, Performance-Based Regulation in a High Distributed Energy Resources Future (Berkeley Lab Jan. 2016) ("Lowry & Woolf PBR Technical Report") at* 1.

[35] Mechanisms that actually and reasonably facilitate the timely recovery of costs prudently incurred in pursuing an action provide an incentive to take the action. An example would be a mechanism, such as the MPIR, which allows recovery of revenue requirements for certain projects between rate cases. Mechanisms that provide incentives to reduce costs, particularly if they limit the ability to recover prudently incurred costs, may provide a disincentive to take actions or achieve results that require investment or other expenditures.

enable attainment of the reduction in the fuel and purchased power expense component of the revenue requirements (all of which flows through to customers). That is, the inability to recover costs is a disincentive to incur the costs.

6. Pursuant to the financial integrity principle, a PBR plan must provide each Company with a reasonable opportunity to recover its prudently incurred costs including a fair rate of return. An MRP can be used to delink revenues from the utility's actual costs between rate cases to provide incentives to contain or reduce costs. Performance incentives can then be added to encourage desired outcomes, and further delink revenues from the utility's actual costs. See Companies' RSOP at 9-12.

- A five-year PBR plan term would be an acceptable feature if the plan also provides for adequate annual revenue adjustments, and tracker/pass through mechanisms that have reasonable scope. In contrast, it would not be acceptable to extend a PBR plan to a five year term if it had inadequate annual revenue adjustment and/or tracker mechanisms that are too limited in scope. The latter plan would not be acceptable because it would not provide a reasonable opportunity to earn the authorized rate of return over the plan term.

7. Financial analyses are important in evaluating the PBR proposals in this proceeding. The adequacy of the ARA (ARA plus Z-factor adjustment plus MPIR adjustment) that is developed in this proceeding should be tested through financial analyses. The Companies appreciate that the Commission has scheduled a Financial Modeling Workshop (Workshop B) in November 2019.

III.

PERFORMANCE INCETIVE MECHANISMS, SCORECARDS, REPORTED METRICS AND SHARED SAVINGS MECHANISMS

III. PIMS, SCORECARDS, REPORTED METRICS AND SSMS

As stated by the Commission, "updates to the State's regulatory framework are designed to support new utility earnings opportunities as an incentive to achieve exemplary performance and business innovation expected of the State's electric utilities. Phase 2 will prioritize development of a portfolio approach to performance mechanisms, which will include Performance Incentive Mechanisms ("PIMs"), Scorecards and Reported Metrics, and Shared Savings Mechanisms ("SSMs")."[36]

Consistent with this guidance, the Companies respectfully submit the following initial versions of proposals for PIMs to help drive achievement of the priority outcomes: *Interconnection Experience; DER Asset Effectiveness and Customer Engagement;* Scorecards to track progress against targeted performance levels for the priority outcomes: *Interconnection Experience, Customer Engagement, Cost Control,* and *GHG Reduction;* Reported Metrics to measure and track relevant utility performance data addressing the outcomes: *Affordability, Customer Equity, Electrification of Transportation, Capital Formation,* and *Resilience;* and a Shared Savings Mechanism to address *Grid Investment Efficiency* and mitigate capex bias, and reward the pursuit of cost effective solutions to meet customer needs. The Companies designed their proposals to be consistent with the Guiding Principles identified by the Commission of utilizing a customer-centric approach, promoting administrative efficiency, and preserving utility financial integrity.

While the Companies have endeavored to develop and propose the most comprehensive initial proposals possible at this time, the Companies are also mindful of the Commission's guidance that "at this stage, the Parties may not yet be able to specify all relevant details in their proposals"

[36] Decision and Order No. 36326 issued in this proceeding on May 23, 2019 ("D&O No. 36326")

and "those proposals can thus be submitted with the understanding that the Parties will submit subsequent, further refined proposals as Phase 2 proceeds, incorporating amendments and additional details in response to feedback from the Working Groups. This iterative process is intended to ensure that the Parties explore, test, and improve their respective proposals prior to their final submission to the commission."[37]

As the Companies move forward with the process established by the Commission, the Companies look forward to discussing, developing and refining their initial proposals further. This would include identifying, securing and utilizing the data necessary to support the proposed mechanisms and in some cases developing sufficient data sets to identify meaningful targets for Scorecards. As the Commission and parties are well aware, jurisdictions across the country are working to develop the type of mechanisms that are being evaluated in this proceeding and there is not yet a great deal of established precedent and experience to look to for guidance. The efforts of the Commission and parties to this proceeding are in many instances at the forefront of these national efforts and therefore it is ever more critical that this process remain attentive to the guiding principles outlined by the Commission to avoid unintended consequences to the greatest degree possible. It is also important to recognize the Commission's admonition that all of the various mechanisms proposed as a part of this proceeding will need to work together as a cohesive whole focusing on "mechanisms which are most likely to be effective, feasible, and implemented within a reasonable timeframe". As discussed in the recent Workshop A on August 7, 2019, financial modeling will be a key part of evaluating whether a particular mechanism or group of mechanisms can work to achieve the goals for and directives from this proceeding.[38]

A. <u>PIMs</u>

[37] Order No. 36388 at 12.
[38] D&O No. 36326 at 52

Through D&O No. 36326, the Commission stated that it "will prioritize the development of between three to six new PIMs, addressing the Outcomes of *Interconnection Experience, Customer Engagement,* and *DER Asset Effectiveness.* For PIMs addressing *Customer Engagement* and *DER Asset Effectiveness,* the commission will explore PIMs with only upside elements; for PIMs addressing *Interconnection Experience,* the commission will explore PIMs with both "upside" and "downside" elements."[39] The Commission also expressly noted that the "development of PIMs requires careful consideration and analysis of the underlying metrics and targets, to ensure that the expected performance, as well as the amount of financial incentives and/or penalties, are reasonable, and that the utility is not exposed to inappropriate financial gain or risk."[40] Consistent with this, the Commission adopted the "PIM-specific design considerations" set forth in the Staff Proposal which include:

> (1) Setting a quantitative standard for performance. The benchmarks/targets, and especially any associated financial incentives, should focus on promoting the achievement of only superior performance or penalizing poor performance.
>
> (2) Benefit-cost analyses should inform the development of PIMs. PIMs should be designed to reflect some sharing of net benefits. This assessment of net benefits sets an upper limit on discussion about the appropriate sharing percentages between ratepayers and the utility shareholders.
>
> (3) PIMs should shift an appropriate amount of performance risk to the utility in exchange for longer-term regulatory certainty and perhaps incentive compensation. Entrepreneurialism on the part of the utility should be rewarded, but PIMs should also ensure the risk and reward is comparable to that of firms in a free and competitive market.
>
> (4) "Double recovery" of PIMs that achieve the same or similar outcome should be minimalized (for example, a program-based [Demand Response] PIM and an outcome-based PIM for improved system load factor or peak demand reduction). Care will need to be taken to ensure that the design of PIMs is coordinated so that multiple utility activities are not double-counting the same benefits and receiving reward for the same outcome(s).

[39] D&O No. 36326 at 11
[40] Id. at 43

(5) Consider designing individual PIMs so that "outstanding" performance on an individual PIM may be rewarded by additional earnings, while maintaining overall earnings caps for all PIMs.

(6) Consider the appropriate time frame for PIMs. PIMs can be designed to span multiple years to allow time for utility actions to take effect.[41]

The Companies propose the following four PIMs for discussion and further deliberation in the working groups, workshops and follow on processes in this proceeding. Each of the PIMs is further discussed in more detail following the summary table.

Outcome	Description of PIM	Target	Maximum Reward	Maximum Penalty
Interconnection Experience Proposal	PIM with a reward or penalty based on timeliness in providing conditional approval of interconnection applications for DER systems less than 100kW	100% of Applications in a calendar year are conditionally approved on median under 10-30 days v. the 50 days required by Tariff.	$500K if 100% of Applications in a calendar year are conditionally approved on median in less than 30 days; and $1M if they are conditionally approved on median in less than 10 days.	$100K for every 5% of Applications in a calendar year that are not conditionally approved on average within Rule 14H tariffed deadlines up to $500K
DER Asset Effectiveness Proposal - *DER Utilization*	Shared savings PIM for DER Asset utilization enabled via DER and DR programs.		30% of demonstrated savings	
DER Asset Effectiveness Proposal - *DER Facilitation*	PIM with reward of $650/kW for the facilitation of DGPV and/or Storage kW installed in a calendar year.	Combination of annual DR and DER targets.	Cannot exceed $650 * annual targets.	
Customer Engagement Proposal - *Advanced Meter Installations*	Annual lump sum PIM if each year's advanced meter installation target is met. PIM scales pro rata depending upon percentage of target met. 90%-100% = $100,000 100% - 110% = $250,000 >110% = $500,000	A target advanced meter installation schedule would be adopted in this docket or in the Grid Modernization Docket. A target schedule could be developed after one year of benchmarking actual installations.	$500,000	

[41] Id. at 43-44

		Reward would be based on performance against the accepted annual advanced meter installation targets.		

1. Interconnection Experience Proposal

As noted by the Commission, "[a]s Hawaii relies more on increasing levels of DER and grid-scale renewable energy projects, ensuring that there is a reliable and timely interconnection process to integrate these resources onto the Companies' grids is critical. Providing financial incentives for exemplary performance with respect to this Outcome is intended to facilitate the interconnection of renewable resources going forward."[42]

DESCRIPTION OF PIM: This PIM would provide a reward or penalty based on timeliness in providing conditional approval of interconnection applications for DER systems less than 100kW in size.

RATIONALE FOR PIM: The Companies have significantly reduced interconnection backlogs for DER systems less than 100 kW in size across programs. Consistent with proposals from Staff and other parties to incorporate a PIM for the timely interconnection of DER systems, this PIM would incentivize the rapid conditional approval for interconnection of 100% of the most prevalent sizes of DER systems in under 30 days, and provide a more robust incentive to sustain exceptional performance where the utilities are able to conditionally approve 100% of these applications in under 10 days. The PIM would also provide a penalty to the extent that conditional approvals are not provided within tariffed timeframes.

DESIGN OF PIM: For systems <100kW in size on all three utility grids, if 100% of applications in a calendar year are conditionally approved on median in under 30 days, the Companies will receive a maximum $500K reward. If 100% of Applications in a calendar year are conditionally approved on median in under 10 days, the Companies will receive a maximum $1M reward. For every 5% of Applications in a calendar year that are not conditionally approved within existing Rule 14H tariffed deadlines, the Companies will receive a penalty of $100K up to a maximum penalty of $500K.

[42] The Companies note that there are PIMs both existing and under consideration associated with the Companies' Phase 1 and Phase 2 RFPs and the utility scale renewable energy projects to be procured pursuant to those RFPs. Accordingly, the Companies' proposed PIM in this phase of the PBR proceeding focuses on the interconnection of smaller customer sited DER systems.

Because this proposed PIM has been designed based upon existing and forecasted interconnection responsibilities and resources, it is necessary to provide certain reasonable guardrails around the incentives and penalty. These include:

- The clock on conditional approval should start from the date of last submittal of the completed application (so it would exclude days when the Companies are awaiting any missing application information from the customer at the beginning of the process) and end on the date the notice of conditional approval is sent;

- The proposed PIM should be tied to the existing Rule 14H. If Rule 14H is modified in the future, such as through a shortening of existing timeframes for compliance, the Companies should have the opportunity to reassess both the incentive and penalties associated with this PIM;

- The proposed PIM should be tied to existing DER programs. If the Commission approves new programs, which could have the result of dramatically increasing the number of applications that need to be processed through Rule 14H, the Companies should have the opportunity to reassess both the incentive and penalties associated with this PIM. Due to the sometimes uncertain timing associated with interconnection of larger SIA and CBRE systems, the Companies propose that these systems be excluded from the incentive or penalty calculation. Similarly, due to the existence of system hosting capacity issues on the neighbor islands that are not as prevalent currently on O'ahu, the incentive or penalty calculation should not apply to otherwise qualifying projects on a neighbor island if the system hosting capacity for that island is exceeded.

- The proposed PIM should exclude force majeure events;

- The proposed PIM should exclude applications from customers who want to sign up for DR programs as this process is new and the Companies do not yet have data associated with implementation. It is possible that applications for DR programs could be included in this PIM at a later time;

- Given existing Company resources, the proposed PIM should include a reasonable cap on the total volume of applications in a given calendar year.

The process for gathering data for the PIM will be through the Companies' Customer Interconnection Tool. Data would be collected monthly for the calendar year determination. Data is currently available for this metric since February 2017. The Companies propose that this PIM have a duration of 3 years at which time it may be revisited.

2. DER Asset Effectiveness Proposals

As the Commission stated in D&O No. 36286, the "Companies have experienced an unprecedented level of DER adoption in recent years, offering an increasing number of evolving and sophisticated DER program options, including Net Energy Metering ("NEM") and NEM+, time-of-use ("TOU"), Customer Self Supply ("CSS"), Customer Grid Supply ("CGS") and CGS+, and Smart Export." The Commission observed that "[a]s the suite of DER options becomes more robust and complex, it is critical that utilities manage these new resources in an efficient manner, such that these resources are maximized while also promoting safe, reliable, electrical service."[43]

As noted by the Commission, for PIMs addressing DER Asset Effectiveness and Customer Engagement, the Commission "will focus on developing "upside-only" PIMs, providing the HECO Companies with financial rewards based on exemplary performance. These are relatively new areas of analysis for the Companies, and this approach will ensure that any metrics and corresponding targets used in designing this initial set of PIMs are appropriate indicators of utility progress in achieving desired outcomes before exposing the utilities to financial penalties."[44]

<u>DER Asset Effectiveness Proposal – DER Utilization</u>

DESCRIPTION OF PIM: This proposed PIM is based on a shared savings approach for DER Asset utilization enabled via DER and DR programs, with a maximum reward equivalent to 30% of estimated savings. If services are procured at less than the determined value of that service, then the savings for customers will be shared. Lower cost procurement of these vital resources will maximize the use of and increase the effectiveness of these assets while also providing system benefits and value to customers.

RATIONALE FOR PIM: This shared savings PIM for the procurement and/or programmatic-based utilization of customer-sited distributed energy resources represents a

[43] D&O No. 36326 at 48
[44] Id. at 49

consistent approach to that which was filed as part of the combined Phase 2 RFP and Grid Services RFP ("proposed Phase 2 RFP PIM") and utilizes as a baseline the DER values developed through the value of services work developed for the DR portfolio. The scope of this PIM would not overlap with the proposed Phase 2 RFP PIM. This currently proposed PIM's structure offers an award based on the realization of system value. These values can be redefined with every iteration of the IGP on a 3 year cycle and create the baseline to define and determine savings. It ties the PIM to cost-efficiencies delivered by the utilization of customer-sited investments including DER utilization specifically that is enabled via DER and DR programs, to the extent that there are variable costs associated with these programs.

DESIGN OF PIM: The Companies have published a value of service for each grid service that DERs can provide on an annual $/kW/service/island basis in the *Revised DR Portfolio Application*, filed on February 10, 2017 in Docket No. 2015-0412. Based on these values, the Companies propose that for each aggregator contract and for each program that calls for the control of DERs for the delivery of grid services, the Companies compare the cost of the collective services offered (either over the 5-year contract or for the discrete program year) against the avoided cost of those services for the corresponding term. The difference between these two numbers would represent the cost savings resulting from each kW utilized. This PIM proposes that customers received 70% of the savings and the Companies receive 30% of the savings.

The savings for aggregator contracts would be assessed at contract execution and paid over the contract term in accordance with successful achievement of enablement targets and aggregator performance. If a Supplier fails to achieve full enablement and/or the Supplier fails to achieve a Performance Factor of 90% or higher in any contract year, the PIM will be subject to a corresponding discount. For programs, the savings on a $/kW basis would be established at the time of the program filing on the basis of the projected program costs and the aforementioned Value of Service for the corresponding service that a given program would enable. These Value of Services will continue to be reassessed as part of the IGP cycle.

For aggregator contracts: 25% of PIM allowed at a successful system integration test (90 days after PUC approval of contract); annual pro rata payment of the remaining 75% paid after each contract year based on the percentage of annual enablement schedule as percentage of total enablement commitment and a Supplier Performance Factor over the year. Having a PIM reward payable over a term of years would to some degree begin to replicate capital investments for which recovery spans over a much longer time frame.

Example: DER Utilization PIM - Aggregator Contract						
GSPA Levelized ($/kW) (a)		$100	GSPA Contract			
Value of Service ($/kW) (b)		$110	Year	Load (kW) (d)	PF (e)	
Levelized Savings ($/kW) (c) = (b) - (a)		$10	Year 1	2,500	95%	
			Year 2	7,500	90%	
Total Savings ($)	(f) = sum of (c)*(d	$325,000	Year 3	7,500	88%	
Company Max PIM (30%)	(g)= 0.3*(f)	$97,500	Year 4	7,500	85%	
			Year 5	7,500	84%	
First payment of 25%	(h) = 0.25*(g)	$24,375	Note 1: Performance Factor (PF)			
At Year 1	(i) = 0.75*0.30*(c)*(d)*1	$5,625	Note 2: PF of 90% - 100% would be paid full amount.			
At Year 2	(i) = 0.75*0.30*(c)*(d)*1	$16,875				
At Year 3	(j) = 0.75*0.30*(c)*(d)*(e)	$14,850				
At Year 4	(j) = 0.75*0.30*(c)*(d)*(e)	$14,344				
At Year 5	(j) = 0.75*0.30*(c)*(d)*(e)	$14,175				
	TOTAL	**$90,244**				

For Programs: the PIM would be awarded annually in full for the previous program year with the annual payment based on a Program Performance Factor over the year based on an annual evaluation.

Example: DER Utilization PIM - Programs						
Program Levelized ($/kW) (a)		$100	Program Enablement			
Value of Service ($/kW) (b)		$110	Year	Load (kW) (d)	PF (e)	
Levelized Savings ($/kW) (c) = (b) - (a)		$10	Year 1	2,500	95%	
			Year 2	7,500	90%	
Total Savings ($)	(f) = sum of (c)*(d	$325,000	Year 3	7,500	88%	
Company Max PIM (30%)	(g)= 0.3*(f)	$97,500	Year 4	7,500	85%	
			Year 5	7,500	84%	
At Year 1	(i) = 0.30*(c)*(d)*1	$7,500	Note 1: Performance Factor (PF)			
At Year 2	(i) = 0.30*(c)*(d)*1	$22,500	Note 2: PF of 90% - 100% would be paid full amount.			
At Year 3	(j) = 0.30*(c)*(d)*(e)	$19,800				
At Year 4	(j) = 0.30*(c)*(d)*(e)	$19,125				
At Year 5	(j) = 0.30*(c)*(d)*(e)	$18,900				
	TOTAL	**$87,825**				

Data for this PIM would be collected monthly and reported annually. The maximum reward for this PIM would be 30% of demonstrated savings and the incentive is proposed to be ongoing.

DER Asset Effectiveness Proposal - DER Facilitation

DESCRIPTION OF PIM: This PIM rewards the Companies for the facilitation of DER MW installed in a calendar year. For DGPV and/or Storage, the Companies propose an up-side only PIM in the amount of $650/kW for each kW of installed capacity in each calendar year. The PIM would be capped on the basis of the total DER installed capacity targets as established in the forthcoming DER Strategy; these will be updated during each IGP refresh cycle.

RATIONALE FOR PIM: This PIM would facilitate the effective use of DER resources, including selection as a non-wires alternative to utility investment. The PIM would enable the

effective utilization of assets as the Companies leverage their grid value, such as through DER programs, pricing to be developed, SIAs, and grid services programs, all which provide the ability for the assets to be used more effectively. This is also designed to result in the utility making specific decisions not to invest in capital assets and instead promote the deployment of customer assets to participate in the grid. The 10% incentive is to offset the capital bias that is being avoided by pursuing DER resources.

DESIGN OF PIM: The $/kW incentive is called "facilitation" specifically because facilitation takes many forms. These would include rates or programs or other offerings that make it attractive for customers to participate, expedient and efficient interconnection processes, better customer interface and support tools, etc. This motivates the Companies to pursue DER deployment in lieu of capital investments. The dollar amount is based on an assumed $6500/kW installed capacity for PV + storage systems. The PIM represents 10% of that cost. Data for this PIM would be collected monthly and reported annually. It is proposed to be an ongoing PIM which would not exceed the $650/kW annual target and would be monitored through the DER interconnection process fulfillment tracking through the CIT. An additional benefit of this PIM is that it will help build the critical mass of participating DER resources that can be leveraged to most effectively and efficiently support the grid.

Example: DER Facilitation PIM		
DER Cost ($/kW)	(a)	$6,500
Company PIM (10%)	(b) = 0.1*(a)	$650
Company PIM Calculation		
Year 1	(c) = (b) * (d)	$1,625,000
Year 2	(c) = (b) * (d)	$4,875,000
Year 3	(c) = (b) * (d)	$6,500,000
Year 4	(c) = (b) * (d)	$6,500,000
Year 5	(c) = (b) * (d)	$6,500,000
	TOTAL	**$26,000,000**

Program Enablement	
Year	DER (kW) (d)
Year 1	2,500
Year 2	7,500
Year 3	10,000
Year 4	10,000
Year 5	10,000

Customer Engagement Proposal – Advanced Meter Installations

As recognized by the Commission, "[u]tilities need to adequately and equitably facilitate a move toward an inclusive, customer-oriented electric grid, as customers evolve from passive consumers of a commodity (kWh) to active participants in a dynamic market for grid services. This not only involves tracking customer participation in the Companies' new program offerings, such as DER, CBRE, and Demand Response, but also developing effective outreach tools to educate customers about their electricity consumption and how they can better manage it

whether it be through energy-saving practices, or taking on a more active role as a market participant or as an energy and grid services provider." "A PIM for the *Customer Engagement* Outcome will focus attention on interaction and experience with the customer, which should be a vital part of an electric utility's business model. A PIM should also incent the utility to leverage its relationship with its customers to collaboratively work towards increasing renewable energy in a manner that serves both utility and customer."[45]

DESCRIPTION OF PIM: An annual lump sum incentive if each year's advanced meter installation target is met.

RATIONALE FOR PIM: A PIM is proposed to offer a performance based incentive to the Companies to promote customer acceptance of advanced meters and the programs that require them and reward advanced meter adoption (i.e., "opt-ins") measured annually against an advanced meter installation target to be developed.

DESIGN OF PIM: An annual lump sum PIM if each year's advanced meter installation target is met. The lump sum figure would scale pro rata depending upon the percentage of target met.

90% - 100% = \$100,000
100% - 110% = \$250,000
> 110%= \$500,000

As noted in the table above, a target advanced meter installation schedule would be adopted in this docket or in the Grid Modernization Docket. A target schedule could be developed after one year, perhaps, of benchmarking actual installations. Reward would be based on performance against the accepted annual advanced meter installation targets. Data for this PIM would be collected monthly and reported annually with a maximum incentive per calendar year of \$500,000 and the initial targets established after one year of meter installations (end of 2020) and revised annually thereafter. This PIM would continue until all advanced meter installations are completed.

B. <u>Scorecards</u>

As described in the Staff Proposal, a Scorecard represents the next level in the Performance Mechanism hierarchy, effectively combining a Reported Metric with a specific benchmark or target, which may "encourage better achievement of regulatory outcomes than

[45] D&O No. 36326 at 47-48

through Reported Metrics alone."[46] Staff proposed using Scorecards to measure and evaluate the Outcomes of: *Interconnection Experience, Customer Engagement, Cost Control,* and *GHG Reduction.*[47] The Commission determined that "the suggested Scorecards represent a valuable opportunity to begin tracking and measuring the Companies' performance in certain areas and supports their development in Phase 2. Accordingly, the commission will focus development of Scorecards for the specific Outcomes set forth in the Staff Proposal."[48]

The Companies propose the following seven Scorecards for discussion and further deliberation in the working groups, workshops and follow on processes in this proceeding. Each of the proposed Scorecards is further discussed in more detail following the summary table.

Outcome	Description of Scorecard Metric	Target
Interconnection Experience Proposal – DER Surveys	Customer and contractor survey about the entire interconnection experience: track number of surveys sent, amount of surveys completed, and provide summary of key results.	100% surveys sent to customers and contractors upon completion of interconnection process
Interconnection Experience Proposal – IPP Survey	IPP feedback about the interconnection experience: meet with each IPP post commercial operations and survey IPP on interconnection experience, including contract negotiation, IRS, IRS Amendment (if applicable), construction of company-owned interconnection facilities, testing, and reaching commercial operations, provide a summary of key results.	Meet with 100% of IPPs and conduct survey within 6 months of such IPP reaching commercial operations.
Customer Engagement Proposal - Customer Portal Usage	Measures customer usage of customer portal against usage targets. Usage targets are reflected as page views.	Average Daily Unique Views
Customer Engagement Proposal – TOU Participation	Measures and tracks the number of TOU customers as a percent of all customers by rate class – on a consolidated basis.	Variable increasingly annually consistent with TOU Program Participation
Cost Control Proposal – Defined O&M	Measures and tracks consolidated A&G, Transmission and Distribution and Customer Services costs per customer and compare changes against a predetermined baseline. A&G expenses exclude pension and benefits, as well as expenses for injuries/damages and regulatory commission expenses.	Annual cost increase should be limited to inflation for the respective year (based on GDPPI)
GHG Reduction	CO2e emissions per year in tons – For each island served	The metrics and targets for this

[46] Id. at 41
[47] Id. at 42
[48] Id.

Proposal – Carbon Emissions	and consolidated	Scorecard would be based on a Production Simulation of the utility's latest resource plan which would be updated every 5 years – or less than 5 years to cover major events (e.g., lava flows shutting down PGV and/or incorporating results of RFP solicitations if they differ significantly from the latest resource plan). The proposed initial targets for this Scorecard would be based upon an updated resource plan that includes all contracted projects, including the Stage 1 RFP projects, and a proxy for the Stage 2 projects or specific Stage 2 projects selected, depending upon the timing of the Scorecard. Data for this metric would be collected on an annual basis and is available historically from 2010
GHG Reduction Proposal – Carbon Intensity	CO_2e intensity per year in grams/kWh – For each island served and consolidated	The metrics and targets for this Scorecard would be based on a Production Simulation of the utility's latest resource plan which would be updated every 5 years – or less than 5 years to cover major events (e.g., lava flows shutting down PGV and/or incorporating results of RFP solicitations if they differ significantly from the latest resource plan). The proposed initial targets for this Scorecard would be determined from the initial baseline plan presented in the IGP, which will be an updated PSIP forecast taking into account the results of the Phase I RFP and a prediction of resources to be obtained via the upcoming Phase II RFP process. Data for this metric would be collected on an annual basis and is available historically from 2010.

Interconnection Experience Proposal – DER Surveys

DESCRIPTION OF SCORECARD – Survey customers and contractors about their interconnection experience: track the amount of surveys sent, amount of surveys completed, and provide a summary of key results.

RATIONALE FOR SCORECARD – Commission Staff suggested tracking the results of developer satisfaction surveys, and other parties suggested DER customer survey results. The survey is anticipated to ask about the customer's experience with both the contractor and the utility. This would include quarterly surveys of contractors to balance the need for timely feedback with a desire not to overwhelm contractors such as with a survey request after each

project is completed. One issue to be aware of as a part of any type of survey scorecard is "survey fatigue" and the tendency of customers not to want to engage in surveys received in an environment where customers receive surveys for virtually every commercial transaction they engage in.

DESIGN OF SCORECARD - Companies send surveys to 100% of customers and contractors upon completion of interconnection process. The frequency of data collection would be quarterly and the Companies presently have data available since 2018.

Interconnection Experience Proposal – IPP Surveys

DESCRIPTION OF SCORECARD – Survey Independent Power Producers (IPPs) for feedback about the interconnection experience: meet with each IPP post commercial operations and survey IPP on interconnection experience, including contract negotiation, IRS, IRS Amendment (if applicable), construction of Company-owned interconnection facilities, testing, and reaching commercial operations, provide a summary of key results.

RATIONALE FOR SCORECARD – Commission Staff suggested tracking the results of developer satisfaction surveys. This will allow the Company to determine IPP satisfaction with the interconnection process from contract negotiation though commercial operation. Once sufficient data is available, results can be examined to identify consistent areas where the process is running well and where improvements may need to be made and the Company can then focus its efforts on the areas where room for improvement is recognized.

DESIGN OF SCORECARD - Meet with 100% of IPPs and conduct survey within 6 months of such IPP reaching commercial operations. Summary of results compiled from each meeting with an IPP to be further compiled on an annual basis. Data in support of this Scorecard will come from the survey results. As this is a new proposed process, there is no historical data available for this proposed mechanism.

Customer Engagement Proposal - Customer Portal Usage

DESCRIPTION OF SCORECARD: Measures customer usage of customer portal against usage targets. Usage targets are reflected as page views measured by average daily unique views.

RATIONALE FOR SCORECARD: As the Companies advance into a modern grid future, the customer portal will serve as the foundation for customer engagement. This will include new program offerings, bill comparisons, electricity consumption data and more. Gauging customer interactions with this tool will serve as a meaningful measure as to how well the Companies are doing at engaging with customers across a variety of initiatives.

DESIGN OF SCORECARD: The Companies propose that the target for this scorecard be set at the end of 2020 after 1 year of customer portal deployment and data availability. Data for this scorecard would be collected monthly as reflected in the customer portal application logs.

Customer Engagement Proposal – TOU Participation

DESCRIPTION OF SCORECARD: This Scorecard would measure and track the number of TOU customers as a percent of all customers by rate class – on a consolidated basis.

RATIONALE FOR SCORECARD: The TOU rate incentivizes customers to use electricity that benefits grid operations. As advanced meters are deployed, the practicality of implementing TOU rates increases. Therefore, the target would increase annually as the number of advanced meters in service increases. Although advanced meters facilitate achieving this scorecard, the measure will be based on customers on both standard and advanced meters. NEM customers, or at least NEM customers who receive a minimum bill for the majority months in a year, should be excluded as with no or little billed usage, NEM customers would significantly be less likely to consider TOU rate options.

DESIGN OF SCORECARD: The target for this scorecard would be variable and increase annually consistent with TOU program participation over time. The target would be based on a survey of domestic utility averages and data for the scorecard would be collected monthly. This scorecard should exclude TOU-EV participation since this rate is scheduled to expire in October of 2020 as well as NEM customers. Data for this metric is available back to 2012 (the SAP CIS implementation date) and can be sourced from the SAP CIS Customer Count Report on a going forward basis.

<u>Cost Control Proposal – Defined O&M</u>

DESCRIPTION OF SCORECARD: This Scorecard would measure and track consolidated A&G, Transmission and Distribution and Customer Services costs per customer .

RATIONALE FOR SCORECARD: The Commission and Staff have identified Operational Expenses as an area of focus.[49]

DESIGN OF SCORECARD: This Scorecard would measure and track consolidated A&G, Transmission and Distribution and Customer Services costs per customer and compare changes against a predetermined baseline. A&G expenses exclude pension and benefits, as well as expenses for injuries/damages and regulatory commission expenses, consistent with how these categories were evidently defined in the Staff Proposal. Target would be annual cost increases limited to inflation for the respective year (based on GDPPI).

<u>GHG Reduction Proposal – Carbon Emissions</u>

DESCRIPTION OF SCORECARD: This GHG Reduction Scorecard for carbon emissions would report and track carbon emissions in tons per year (for each island and also consolidated) limited to the electric sector.

RATIONALE FOR SCORECARD: As discussed in the Staff Proposal, "reducing the greenhouse gas (GHG) emissions of Hawaii's electricity system is a priority, as evidenced by

[49] *See* Staff Proposal for Updated Performance-Based Regulations, submitted in this proceeding on February 7, 2019 ("Staff Proposal"), at pgs. 7-8.

HB 2182, recent legislation that sets a goal of carbon neutrality by 2045. Where the 100% RPS standard imposes a requirement to increase the share of renewable energy supply in the power system, the GHG Reduction outcome offers a different focus aimed more directly at reducing emissions attributable to the power system."[50] "This prioritized outcome may be best addressed through Performance Mechanisms, such as reported metrics or scorecards to track utility performance, and potentially compare it against peer utilities."[51]

DESIGN OF SCORECARD: The metrics and targets for this Scorecard would be based on a Production Simulation of the utility's latest resource plan which would be updated every 5 years – or less than 5 years to cover major events (e.g., lava flows shutting down PGV and/or incorporating results of RFP solicitations if they differ significantly from the latest resource plan). The proposed initial targets for this Scorecard would be based upon an updated resource plan that includes all contracted projects, including the Stage 1 RFP projects, and a proxy for the Stage 2 projects or specific Stage 2 projects selected, depending upon the timing of the Scorecard. Data for this metric would be collected on an annual basis and is available historically from 2010.

<u>GHG Reduction – Carbon Intensity</u>

DESCRIPTION OF SCORECARD: This GHG Reduction Scorecard for carbon intensity would report and track carbon emission intensity per grams/kWh per year (for each island and also consolidated) limited to the electric sector. The amount of kWh per year used in the calculation would include net energy produced by the utility and IPPs as well as an estimate of energy produced from DER resources.

RATIONALE FOR SCORECARD: As discussed in the Staff Proposal, "reducing the greenhouse gas (GHG) emissions of Hawaii's electricity system is a priority, as evidenced by HB 2182, recent legislation that sets a goal of carbon neutrality by 2045. Where the 100% RPS standard imposes a requirement to increase the share of renewable energy supply in the power system, the GHG Reduction outcome offers a different focus aimed more directly at reducing emissions attributable to the power system."[52] "This prioritized outcome may be best addressed through Performance Mechanisms, such as reported metrics or scorecards to track utility performance, and potentially compare it against peer utilities."[53]

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[50] Staff Proposal, Appendix A at 5
[51] Id.
[52] Id.
[53] Id.

Scorecard. Data for this metric would be collected on an annual basis and is available historically from 2010.

C. Reported Metrics

As noted by the Commission in D&O No. 36326, "[m]etrics can be designed as activity-, program-, and outcome-based. Different types of metrics may be appropriate for a specific indicator or measurement, and a mix or blended portfolio of metric types may be warranted in the Hawaii context." "The simple act of tracking and reporting metrics can incent utilities toward stronger performance by using transparency as a regulatory tool."[54]

The Commission through its Decision & Order also found that the "five principles for metric design" should: (l) reflect desired outcomes; (2) be clearly defined; (3) be quantifiable through reasonably available data; (4) be easily interpreted; and (5) be easily verified; and that Staff's proposal to develop Reported Metrics to measure the following Outcomes: *Affordability, Customer Equity, Electrification* of *Transportation, Capital Formation,* and *Resilience* were reasonable.[55]

The Companies propose the following ten Reported Metrics for discussion and further deliberation in the working groups, workshops and follow on processes in this proceeding. Each of the proposed Reported Metrics is further discussed in more detail following the summary table.

Outcome	Description of Metric
Electrification of Transportation Proposal – Public Charging Stations	Number of all public charging stations, by type
Electrification of Transportation Proposal – Energy Delivered from Charging Stations	Mid-day Energy Delivered from Company-owned charging stations in aggregate of all islands
Capital Formation Proposal –	Building permit value of rooftop PV deployed per island

[54] D&O No. 36326 at 39
[55] Id. at 40-41

Building Permit Value	
Capital Formation Proposal – Megawatts of third party generation on system	MWs of non-utility generation on the system
Resilience Proposal - Certification	Number of employees completing National Incident Management System Incident Command System 100, 200, and 300 Certification.
Resilience Proposal - Training	Attend Emergency Response Training - total number of employees
Affordability Proposal – Residential Bill	Typical monthly bill Schedule R
Affordability Proposal – Percentage of annual LIHEAP income	Typical monthly bill as percentage of annual income for LIHEAP-eligible family of 4
Customer Equity Proposal - CBRE	CBRE: number and % of LMI Subscribers
Customer Equity Proposal – Subsidy Tracking	Subsidization by Non-Participating Customers

Electrification of Transportation Proposal – Number of Public Charging Stations

DESCRIPTION OF REPORTED METRIC - Number of all public charging stations, by type.

RATIONALE FOR REPORTED METRIC: Availability of public charging is one of the primary barriers to adoption of clean transportation. Awareness of the number of charging stations will provide visibility into infrastructure availability and help identify market gaps in deployment and technology. Identifying lack of charging infrastructure will provide a data driven basis for continued deployment of charging stations. This metric can also identify the extent of non-utility infrastructure investment which could support the development of policy initiatives to fill market gaps.

DESIGN OF REPORTED METRIC: This reported metric would be limited to the Companies' Service Territories. Data for this metric would be collected on an annual basis and is anticipated to be collected from resources such as Plugshare or DBEDT (EV Hawaii) or DOE AFDC. The Companies look forward to discussing with the parties the accuracy and usefulness of these resources and whether there are better sources of information available to support this metric.

Electrification of Transportation – Energy Delivered from Company-Owned Charging Stations

DESCRIPTION OF REPORTED METRIC: Mid-day Energy Delivered from Company-owned charging stations in aggregate of all islands - limited to the Companies' service territories.

RATIONALE FOR REPORTED METRIC: Shifting energy consumption to the daytime aligns with the Companies' objective to maximize the use of renewable generation, which occurs during the day. Identifying mid-day load from Company-owned charging stations enables the analysis of the effectiveness of rate design and incentives. This metric also helps to quantify the effect of rate structure on increasing revenue contribution to the Companies' fixed costs,

providing a clear reflection of the cost/benefit analysis, as illustrated in the EoT Roadmap. The metric also provides insight into the Companies' ability to ensure the availability and utilization of the charging infrastructure.

DESIGN OF REPORTED METRIC. Data for this metric would be collected on an annual basis. Historical information is available for this metric from December of 2017 (the 2013-2017 rate structure was flat fee and overnight period was lowest cost).

Capital Formation Proposal – Building Permit Value of Rooftop PV

DESCRIPTION OF REPORTED METRIC: Building permit value of rooftop PV deployed per island.

RATIONALE FOR REPORTED METRIC: This metric was suggested by Commission Staff. Staff also defined this Capital Formation outcome as including the following considerations: "Beyond the utility, capital formation also can refer to the ability of third parties and customers to invest in new energy technologies at sufficient scale. Traditionally, this outcome has been focused almost exclusively on the utility's credit rating and financial health. Going forward, this outcome could begin to consider broader capital flows in the electricity sector. The increasingly diverse and competitive marketplace for energy services suggests that regulations do not serve their societal objectives through a narrowly constructed view to only promote the financial health of the utility. Rather, while indisputably an important regulatory consideration, the utility's financial profile should be evaluated along with other sources of market investment that can serve customer and societal needs. . . . Including this outcome among others can, at a minimum, provide a useful reference to monitor overall conditions and place the utility in the context of broader market health. A proposed performance mechanism considered for this regulatory outcome may seek to support capital formation at three related levels: the utility level, third-party market participants, and the consumer. . . . This could be measured in many ways; for example, through a record of total annual investment in the State's electricity sector; total non-utility investment in the electricity sector[.]"[56]

DESIGN OF REPORTED METRIC: Data for this metric would be collected quarterly. Historic information is available since 2005 from the DBEDT website. Going forward information can be provided by DBEDT or other third parties including the parties to this proceeding.

Capital Formation Proposal – Megawatts of third party generation on system.

DESCRIPTION OF REPORTED METRIC: This would report on total megawatts of generation provided to the grid by non-utility entities. This metric could be broken out by resource type (i.e., utility scale IPPs, FIT, DER, etc.). This metric could also include these megawatts as a percentage of total generation on system.

[56] Staff Proposal, Appendix A at 3-4

RATIONALE FOR REPORTED METRIC: The level and percentage of third party-financed generation is a high level indication over time of third party ability to raise capital for these investments.

DESIGN OF REPORTED METRIC: Data for this metric can be collected annually or semi-annually and provided by the Companies.

Resilience Proposal - Certification

DESCRIPTION OF REPORTED METRIC: Number of employees completing National Incident Management System ("NIMS") Incident Command System 100, 200, and 300 Certification.

RATIONALE FOR REPORTED METRIC: The electric utility industry is moving toward adoption of NIMS as the standard for Emergency Response to better align with FEMA/Federal Response. Hawaii state and county organizations are familiar with NIMS. Employee certification of NIMS training is a key indicator of Resilience and ability to restore electric service following an emergency

DESIGN OF REPORTED METRIC: Data for this metric can be collected annually. Historic information is available from 2017 and can be provided through FEMA certification.

Resilience Proposal - Training

DESCRIPTION OF REPORTED METRIC: Attendance for Emergency Response Training - total number of employees.

RATIONALE FOR REPORTED METRIC: In addition to specific NIMS certifications, all employees have a role to play in emergency response. Often their emergency response role is not their normal role, so annual training for Incident Command system roles and an exercise are important to maintain proficiency. Section 5.3 of the Electric Service Restoration Plan specifies this requirement

DESIGN OF REPORTED METRIC: Data for this metric can be collected annually. Historic information is available from 2017 and can be provided by the Company regarding annual internal and external training/drill reporting. This metric should also reflect what is currently being developed through the IGP Resilience Working Group.

Affordability Proposal – Residential Bill

DESCRIPTION OF REPORTED METRIC: Typical residential monthly bill - Schedule R

RATIONALE FOR REPORTED METRIC: Provides basic measurement of the cost of residential electricity on an annual basis.

DESIGN OF REPORTED METRIC: Data will be collected quarterly or annually by the Companies' Pricing Division

Affordability Proposal – Percentage of annual LIHEAP Income

DESCRIPTION OF REPORTED METRIC: Typical monthly bill as percentage of annual income for LIHEAP-eligible family of 4.

RATIONALE FOR REPORTED METRIC: This aims squarely at the group most affected by affordability, families of four who qualify for utility bill assistance through federal LIHEAP program. Current bill would be 4.8% of annual income.

DESIGN OF REPORTED METRIC: Data will be collected quarterly or annually by the Companies' Pricing Division and include State DHS and Federal HUD program data.

Customer Equity Proposal – CBRE

DESCRIPTION OF REPORTED METRIC: CBRE: number and % of LMI Subscribers.

RATIONALE FOR REPORTED METRIC: Overall, a good metric for the Company and the State to track and have visibility on. This is a Staff suggested metric and CBRE should be a primary way the Companies address the LMI segment of customers. Additionally, in both the Company's Administrator role and/or in a Utility build scenario, the Companies will have access to this data and can report on it.

DESIGN OF REPORTED METRIC: Data will be collected quarterly or annually most likely from the CBRE Portal. Because this is a new program, historical data is not yet available.

Customer Equity Proposal – Subsidization by Non-Participating Customers

DESCRIPTION OF REPORTED METRIC: Subsidization by Non-Participating Customers.

RATIONALE FOR REPORTED METRIC: Already reporting on this annually for NEM customers; reported as lost contributions to fixed costs in annual NEM report.

DESIGN OF REPORTED METRIC: Data will be collected annually from the Companies' Pricing Division and can be updated to include any new DER programs.

D. Shared Savings Mechanisms

Through its D&O, the Commission stated that it "will include SSMs as part of its examination of Performance Mechanisms to address the Outcomes of *Grid Investment Efficiency*

and *Cost* Control."[57] SSMs, as described in the Staff Proposal, "reward a utility for reducing expenditures from a baseline or projection by allowing it to retain a portion of savings as profit while returning the remainder to ratepayers."[58] The Commission noted that it "believes SSMs provide an opportunity to incent the Companies to improve performance with respect to the priority Outcomes of *Grid Investment Efficiency,* by addressing utility capital bias, and *Cost Control,* by rewarding the Companies for pursuit of cost effective solutions to meet customer needs." "Furthermore, the commission observes that the Companies have recent experience with a similarly-structured PIM in their efforts to competitively procure grid-scale renewable energy generation, which can inform discussions in Phase 2. Thus, although categorized as an "Other Regulatory Mechanism" in the Staff Proposal, the commission believes SSMs are ripe for consideration as part of the larger examination into Performance Mechanisms."[59]

The Companies propose the following Shared Savings Mechanism for Grid Investment Efficiency for discussion and further deliberation in the working groups, workshops and follow on processes in this proceeding. The proposed Shared Savings Mechanism, including the identified SSM for Cost Control, is further discussed in more detail following the summary table.

Outcome	Description of Mechanism	Target	Maximum Reward	Maximum Penalty
Grid Investment Efficiency – 1st Proposal	Shared savings of costs stemming from use of NWA compared with traditional transmission or distribution solution		n/a	n/a

<u>Grid Investment Efficiency Proposal</u>

DESCRIPTION OF SHARED SAVINGS MECHANISM: Shared savings of costs stemming from use of NWA compared with traditional transmission or distribution solution.

RATIONALE FOR SHARED SAVINGS MECHANISM: As noted by the Commission, "SSMs provide an opportunity to incent the Companies to improve performance" with respect to

[57] D&O No. 36326 at 12
[58] Staff Proposal at 40
[59] D&O No. 36326 at 50-51

the priority outcome of *Grid Investment Efficiency,* by addressing utility capital bias, and by rewarding the Companies for pursuit of cost effective solutions to meet customer needs."[60]

DESIGN OF SHARED SAVINGS MECHANISM: Cost difference (on net present value basis) of utility cost of NWA solution contracted or built compared with cost estimate of traditional solution. Data would be collected on an annual basis. Some data exists where Varentec EMGOs and customer advanced inverter functions avoided or deferred traditional distribution upgrade solutions. The shared savings would be split equally between customers and the utility and is anticipated to be an ongoing mechanism.

Cost Control Shared Savings Mechanism

The Companies appreciate the opportunity to propose a Shared Savings Mechanism for cost control recognizing that it is a critical matter for the Commission, customers and the utilities. As the Companies consider the interrelationship of these various mechanisms however, and the Commission's admonition that these mechanisms much all work together as a whole, the Companies are mindful of the Commission's direction that:

> *An MRP (fixed multi-year period without general rate cases) with an index-driven ARM serve as a fundamental driver of incentives for cost control. To the extent each utility can lower expenses during the MRP interim "control period," savings would be realized by the utility as increased earnings.*
>
> ***
>
> *A utility's expenses and revenues can be expected to increase with inflation, offset by increases in productivity that utilities (and all industries) experience. Productivity can flow from numerous factors, including technological improvements, workforce development, innovation, capital investment, and lower costs.*[61]

"Ideally, a composite, index-driven ARM would encourage the utilities to seek economies based on optimal allocation of operating and capital expenditures."[62]

The Companies agree that the MRP contemplated for this proceeding will serve as a fundamental drive of incentives for cost control and due to the uncertainty regarding how a

[60] Id.
[61] Staff Proposal at 25-26
[62] Id. at 27

shared savings mechanism for cost control should work in the context of the MRP cost control incentive the Companies have deferred making a specific proposal for this mechanism at this time. To the extent that there is an opportunity as the PIM working group process progresses, the Companies look forward to better understanding, discussing and as necessary developing a proposal for the Commission's consideration.

IV.

CONCLUSION

IV. CONCLUSION

The Companies appreciate the opportunity to present their Initial Comprehensive Proposal and will continue to advance this discussion in Phase 2 of this proceeding.

DATED: Honolulu, Hawai'i, August 14, 2019.

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Designing Revenue Adjustment Indexes for Hawaiian Electric Companies

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Executive Summary

Hawaii's Public Utilities Commission recently issued the Phase 1 decision in its proceeding on a new performance-based regulation framework for the Hawaiian Electric Company ("HECO") and its utility affiliates. A multiyear rate plan ("MRP") will feature index-driven adjustments to allowed revenue. The revenue adjustment index formula will include an inflation factor, a predetermined productivity (aka "X") factor, and a consumer dividend.

Pacific Economics Group Research LLC personnel pioneered the use of input price, productivity, and other statistical cost research to design rate and revenue adjustment indexes for energy utilities. HECO has asked us to undertake research to aid development of revenue adjustment indexes. This is a report on our research to date.

X Factor

Theoretical Underpinnings

We discuss principles for the design of revenue adjustment indexes in Section 3 of our report. A key result is that, if the gross domestic product price index ("GDPPI") is the sole inflation measure, the X factor should reflect the industry productivity growth trend and an inflation differential. The inflation differential is the difference between the trends in the GDPPI and industry input prices. This matters because GDPPI growth has historically been slowed by the brisk growth in the productivity of the U.S. economy.

The productivity growth of a utility is influenced by many drivers that are beyond its control. For example, slow demand growth reduces opportunities to increase capacity utilization and realize incremental scale economies. An unusually large share of assets nearing retirement age can create an outsized need for capex. It is possible, then, for the expected productivity growth of a utility to differ from the industry trend during an MRP for reasons that are beyond its control.

Theoretical analysis also suggests that a revenue adjustment index should have a scale escalator that measures growth in the operating scale of the subject utility. For vertically integrated utilities such as the HECO Companies, it makes sense to consider multidimensional scale indexes that take a weighted average of growth in the scale of generation, transmission, and distributor services. If an MRP does not compensate a utility for growth in its operating scale, the expected growth in the scale of the utility is an implicit stretch factor.

Empirical Research

We gathered a sample of publicly available data on the operations of 45 U.S. vertically integrated electric utilities ("VIEUs") to calculate the X factor that would have been compensatory on average had these utilities been subject to revenue adjustment indexes featuring GDPPI as the inflation measure. The resultant "Kahn method" X factors reflect the appropriate inflation differential as well the base productivity trend but does not itemize them. We excluded from these calculations costs of nuclear and hydroelectric generation and certain other itemized costs that are not pertinent to the situation of the HECO Companies.

We found that the indicated Kahn X factor was **-1.04%** for the full 1997-2017 sample period. The X factor was even more negative for more recent sample periods, falling to **-1.41%** for the last fifteen years (2003-2017) and to **-2.35%** for the last 10 years (2008-2017). In these calculations, we found that growth in the capital cost of VIEUs was much more rapid than growth in their non-fuel O&M expenses. The rate base grew especially rapidly, and its growth tended to accelerate materially after 2006.

We also considered the appropriate inflation differential. For each VIEU in our sample we calculated a multifactor index of the growth in prices of pertinent base rate (non-energy) inputs. In these calculations, we used a capital price index designed to mimic the traditional cost of service treatment of capital used in utility ratemaking. The trend in this index depends on trends in electric utility construction costs and the rate of return on capital. We used the input price indexes to calculate the average inflation differential for the sampled companies. The growth trend in the industry input price indexes was found to be substantially more rapid on average than that of the GDPPI. Over the full 1997-2017 sample period, industry input price growth exceeded GDPPI growth each year by 0.99% on average. The inflation differential was similar over the last fifteen years of the sample but worsened to -1.38% over the last ten years of the sample, due chiefly to slower GDPPI inflation since the recession of 2008.

The difference between the Kahn X factor and the inflation differential is a rough estimate of the multifactor *productivity* growth trend of VIEUs. Over the full sample period, we found that productivity thus calculated declined by about 0.05% annually on average. Productivity averaged a 0.54% decline over the last fifteen years and a 0.97% decline over the last ten years.

The slowing productivity growth of VIEUs merits explanation. Slower demand growth has reduced the industry's ability to increase capacity utilization and realize new scale economies. Meanwhile, the industry has made sizable capital expenditures in order to install pollution controls, generate more power from renewable resources and cleaner-burning natural gas, and modernize the grid. Important improvements in utility performance such as reduced pollution are not captured by our productivity calculations.

Consumer Dividend

The consumer dividend term of a revenue adjustment index should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target for reasons that are within the company's control. This depends in part on how the performance incentives generated by the MRP compare to those in the regulatory systems of utilities in the cost trend studies that are used to set the X factor. It also depends on the utility's operating efficiency at the start of the plan. The productivity growth of the utility should be more rapid to the extent that its initial inefficiency is greater.

Precedents

In Section 4 of the report we consider precedents for rate and revenue adjustment indexes in North American MRPs. We find that base productivity trends and stretch factors approved by regulators have been falling. X factors are typically lower when a macroeconomic price index such as the GDPPI is the sole inflation measure in the formula. The average X factor in current U.S. rate and revenue adjustment indexes is **-1.27%**. The average stretch factor in current North American MRPs is **0.22%.** Negative X factors are also common in Australian and British MRPs for energy utilities.

Plans with rate or revenue adjustment indexes often provide supplemental revenue for utilities with high capex requirements. The mechanisms for providing supplemental capital revenue vary. Precedents in Alberta, British Columbia, and Ontario are discussed in the report.

Application to the HECO Companies

Some special considerations are pertinent in an application of our research results to the design of revenue adjustment indexes for the HECO Companies. These Companies will have trackers for the cost of major plant additions. However, major plant additions typically account for less than half of the Companies' total additions. There may be markdowns on the capex that is otherwise eligible for tracker

treatment. Moreover, the revenue adjustment indexes will not include scale escalators. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes.

1. Introduction

Hawaii's Public Utilities Commission ("PUC" or "the Commission") recently issued the Phase 1 decision in its proceeding to develop a new performance-based regulation ("PBR") framework for the Hawaiian Electric Company ("HECO") and its utility affiliates.[1] A multiyear rate plan ("MRP") will feature index-driven adjustments to allowed revenue which the Commission calls annual revenue adjustments ("ARAs"). The ARA formula will include an inflation factor, a predetermined productivity (aka "X") factor, and a consumer dividend.

Pacific Economics Group Research LLC ("PEG") personnel pioneered the use of input price, productivity, and other statistical cost research to design rate and revenue adjustment indexes for energy utilities. We have led the field since the 1990s and have worked on previous HECO PBR initiatives. Work for diverse clients has given us a reputation for objectivity and commitment to sound research methods. HECO has asked us to undertake empirical research to aid development of its ARA indexes.

This is a report on our work to date. Section 2 provides some pertinent background information on the regulation of the HECO Companies. In Section 3 we discuss the logic of using statistical cost research to design revenue adjustment indexes. There follows in Section 4 a discussion of notable precedents. Our empirical research for the HECO Companies is discussed in Section 5. Some topics are discussed in greater detail in the Appendix.

[1] Hawaii PUC, Proceeding to Investigate Performance-Based Regulation (2018-0088), Decision and Order No. 36326, May 23, 2019.

2. Background

The Hawaii PUC's Phase 1 decision sketched the outline of a new PBR framework for HECO and its utility affiliates. Each Company will operate under an MRP that features a revenue adjustment index. Revenue requirements that are currently in effect or reset in pending rate cases will serve as the cast-off levels for these indexes. Revenue decoupling will continue, and performance metric systems will be expanded. The terms of these plans will be 5 years.

The index formula will include an inflation factor, an X factor, and a consumer dividend, but not a scale escalator. The Commission stated that the inflation factor would be linked to "a published inflation index" but did not choose the index. PUC Staff stated in their February 7th report that

> The inflation measure [in an MRP] is often a macroeconomic price index such as the Gross Domestic Product Price Index ("GDPPI"); however, custom indexes of utility input price inflation are sometimes used in ARM design. The appropriate inflation measure will be an important consideration of Phase 2.[2]

Regarding the productivity factor, Staff stated in the same report that

> The productivity, or "X" factor, usually reflects the average historical trend in the multifactor productivity of a group of peer utilities. Phase 2 will need to determine the appropriate value for X; however, base productivity trends chosen by North American regulators for X factor calibration have tended to lie in a fairly narrow range to date (e.g., zero to 1 percent).[3]

Most of the Companies' existing cost trackers and pass through mechanisms will continue in their next generation MRPs unchanged. These mechanisms include the Energy Cost Recovery Clause ("ECRC"), the Purchased Power Adjustment Clause, trackers for pensions and other post-retirement benefit costs, the IRP/DSM surcharge, and costs related to Hawaii's third-party DSM administrator.[4] The ECRCs would retain the fossil fuel cost risk sharing mechanism which, for HECO, requires it to absorb 2% of fossil fuel cost variances relative to baseline prices that are reset annually, as adjusted for generator heat rates, up to a cap of $2.5 million.

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[2] Hawaii PUC, *Staff Proposal for Updated Performance-Based Regulations*, February 7, 2019, p. 26.

[3] *Ibid.*, pp. 26-27.

[4] The IRP/DSM surcharge is also used to address variances of the variable costs of demand response programs from amounts reflected in base rates.

Supplemental funding for capex is provided through Major Project Interim Recovery ("MPIR") Adjustment Mechanisms and Renewable Energy Infrastructure Project ("REIP") surcharges. Decision and Order No. 36326 stated that the Commission may consider revisions to the MPIR Guidelines in Phase 2.

> The commission will preserve a mechanism for interim cost recovery for exceptional projects, to the extent that it may not be feasible to appropriately provide cost recovery for all such investments during the MRP exclusively through the ARA. At this time, the commission envisions that extraordinary relief for eligible projects will continue to be governed according to the MPIR Guidelines; however, the commission may consider revisions to the MPIR Guidelines in Phase 2, in order to remain consistent with the principles, goals, and outcomes of the PBR framework described herein, as well as the specific PBR Mechanisms under consideration.

[Decision and Order No. 36326 at 10, footnote excluded.]

MPIR trackers address costs of major capital expenditure ("capex") projects, net of any related benefits that can be quantified and realized by the Companies, if they aren't already offset in rates. Major projects must involve capital expenditures net of customer contributions in excess of $2.5 million and may include, but are not restricted to, those for renewable energy interconnection and generation, those that encourage or enable energy efficiency and clean energy choices, grid modernization, and smaller qualifying projects grouped into programs for review. Capital costs do not flow through the mechanism until the project is deemed used and useful.

MPIR applications must include a business case for the project. These mechanisms cap recovery at the lesser of forecasted or actual cost. The depreciated balance of capex in excess of project caps may be considered for inclusion in rate base during a subsequent rate case.

Ratemaking treatments of capex may have additional incentivizing provisions that are determined on a case by case basis. For the Schofield Generating Station project, a load-following bio-fueled diesel generating station located on an army base, only 90% of the allowed capital costs were addressed through the MPIR. The depreciated balance of capital costs in excess of 90% of the project cost cap will be addressed in a subsequent HECO rate case. The MPIR tracker for this project also addresses incremental O&M expenses offset by any O&M cost savings and reduced emission fees related to the reduced use of other peaking units.

The HECO Companies recently received approval of MPIR trackers to address capital costs related to Phase 1 of their Grid Modernization Project, including costs of advanced meters, a master

data management system, and a telecommunications network.[5] In each case, costs are capped at the lesser of actual costs (in total or per meter installed) and forecasts.

Renewable Energy Infrastructure Program ("REIP") surcharges can expedite recovery of capex and other related costs incurred to accommodate renewables on a project by project basis. Projects that may be addressed by this mechanism include those needed to maintain current renewable energy resources and/or to encourage the connection of new third party renewable energy projects to any of the Companies' systems; projects that encourage development of renewable energy resources by increasing the system's ability to accept more renewable energy on the HECO Companies' systems; and projects that encourage renewable choices and/or otherwise enhance renewable energy choices for customers.[6] The REIP surcharge is limited to 100% of approved eligible project costs. The Companies can request recovery of the depreciated balance of any capex overruns in subsequent rate cases. Recovery through the REIP surcharge does not begin until the project is deemed used and useful. The surcharge has been used to address the costs of several projects including a demand response management system, wind implementation studies, and at least one wind interconnection.

The Commission's Phase 1 decision also included a Z-factor as part of the revenue adjustment index. While the details of the eligibility criteria for Z-factors will be addressed in Phase 2, the PUC clarified the difference between Z-factors and the MPIR.

> Parties should consider relief provided under the MPIR adjustment mechanism as distinct from potential relief under the "Z-Factor" component of the MRP indexed revenue formula. "Z-Factor" events are intended to address unforeseen events and are considered in <u>determining</u> the amount of allowed revenue in accordance with the ARA formula, whereas the MPIR Guidelines are used to <u>prospectively</u> seek relief for planned "eligible projects" <u>in addition to</u> revenue determined by the indexed revenue formula.[7]

The Commission has proposed changing the HECO Companies' current earnings sharing mechanisms ("ESMs"), which asymmetrically refund to customers 25-90% of all overearnings, to mechanisms that would share negative as well as positive earnings variances that are outside of a dead band. The PUC indicated that the ESM could address overearning and under earning differently. Details on the implementation of the ESM will be addressed in Phase 2, including the mechanism's impact on

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[5] The HECO Companies will also be able to continue to keep meters replaced through the AMI project in rate base until they are fully depreciated.

[6] AMI was provided as an example of a project that could encourage renewable energy choices and/or enhance renewable energy choices for customers.

[7] Hawaii PUC (2019), *op. cit.*, p. 35.

the HECO Companies' incentives to contain cost. The Commission also expressed interest in considering off-ramp mechanisms as part of Phase 2. Details of potential off-ramps will be considered as part of Phase 2.

The Commission adopted Staff's proposal to prioritize 12 regulatory outcomes in the performance metric system. Regulatory outcomes may be addressed by one or more of the following: performance incentive mechanisms ("PIMs"), scorecards where performance is reported relative to targets, and reporting-only metrics. The existing set of PIMs that address some dimensions of reliability and customer service performance will be maintained, while the PUC intends to add 3-6 new PIMs for selected regulatory outcomes.[8] The PUC also endorsed the potential of shared savings mechanisms to address the Companies' incentive to prefer capital solutions.

The PUC also encouraged the Companies to work with stakeholders to develop a proposed framework for expedited review of innovative pilot projects. This would occur outside of the Phase 2 proceeding.

[8] The HECO Companies also had time-limited PIMs for cost-effective renewables procurement and demand response with deadlines of March 31, 2019 and December 31, 2018, respectively.

3. Principles of ARA Index Design

3.1 Cost Trend Research and its Use in Regulation

This section of the report considers some technical and theoretical issues that arise in statistical cost research to design revenue adjustment indexes for the HECO Companies. We begin with an introduction to input price and productivity indexes. There follows a discussion of their use in revenue adjustment index design.

Basic Indexing Concepts

Input Price and Quantity Indexes

The growth rate of a company's cost can be shown to be the sum of the growth in a cost-weighted input price index ("*Input Prices*") and input quantity index ("*Inputs*").

$$\textit{growth Cost} = \textit{growth Input Prices} + \textit{growth Inputs} \tag{1}$$

These indexes summarize growth in the prices and quantities of the various inputs that a company uses. Capital, labor, and miscellaneous materials and services are the major classes of base rate (non-energy) inputs used by gas and electric utilities. These are capital-intensive businesses, so the heaviest weights are placed on the capital subindexes.

Productivity Indexes

The Basic Idea A productivity index is the ratio of an output quantity (aka scale) index ("*Outputs*") to an input quantity index.

$$\textit{Productivity} = \frac{\textit{Outputs}}{\textit{Inputs}}. \tag{2}$$

It is used to measure the efficiency with which firms convert production inputs into the goods and services that they provide. Some productivity indexes measure productivity *trends*. The growth of a productivity trend index is the difference between the growth of the output and input quantity indexes.

$$\textit{growth Productivity} = \textit{growth Outputs} - \textit{growth Inputs}. \tag{3}$$

Productivity grows when the output index rises more rapidly (or falls less rapidly) than the input index. Productivity can be volatile for various reasons that include fluctuations in output and/or the

uneven timing of certain expenditures. The volatility of productivity growth tends to be greater for individual companies than the average for a group of companies.

The scope of a productivity index depends on the array of inputs that are addressed by the input quantity index. A *multifactor* productivity ("MFP") index measures productivity in the use of multiple inputs. Some indexes measure productivity in the use of a single input class such as labor. These indexes are sometimes called *partial* factor productivity ("PFP") indexes.

Output Indexes The output (quantity) index of a firm summarizes growth in its outputs or operating scale. If the index is multidimensional, the growth in each output dimension that is itemized is measured by a sub-index. Growth in the summary index is a weighted average of the growth in the sub-indices.

In designing an output index, choices concerning sub-indices and weights should depend on the way the index is to be used. One possible objective of output research is to study the impact of output growth on *cost*.[9] In that event, the index should be constructed from one or more output (aka scale) variables that measure dimensions of "workload" that drive cost. If there is more than one output variable, the weights for these variables should reflect their relative cost impacts.

The sensitivity of cost to a small change in the value of an output or any other business condition variable is commonly measured by its cost "elasticity." Cost elasticities can be estimated econometrically using data on the costs of utilities and on outputs and other business conditions that drive these costs. Such estimates provide the basis for elasticity-weighted output indexes.[10] An MFP index calculated using a cost-based output index ("$Outputs^C$") will be denoted as MFP^C.

$$growth\ MFP^C = growth\ Outputs^C - growth\ Inputs. \qquad [4]$$

This may fairly be described as a "cost efficiency index."

[9] Another possible objective is to measure the impact of output growth on *revenue*. In that event, the sub-indices should measure trends in *billing determinants* and the weight for each itemized determinant should reflect its share of revenue.

[10] An early discussion of elasticity-weighted output indexes is found in Denny, Michael, Melvyn A. Fuss and Leonard Waverman (1981), "The Measurement and Interpretation of Total Factor Productivity in Regulated Industries, with an Application to Canadian Telecommunications," in Thomas Cowing and Rodney Stevenson, eds., *Productivity Measurement in Regulated Industries*, (Academic Press, New York) pages 172-218.

Sources of Productivity Growth

Economists have studied the drivers of productivity growth using mathematical theory and empirical methods.[11] This research has found the sources of productivity growth to be diverse. One important source is technological change. New technologies permit an industry to produce given output quantities with fewer inputs.

A second important source of productivity growth driver is output growth. In the short run, output growth can spur a company's productivity growth to the extent that it has excess capacity. In the longer run, economies of scale can be realized even if capacity additions are required to the extent that cost tends to grow less rapidly than output. Increased capacity utilization and incremental scale economies will typically be lower the slower is output growth.[12]

A third important productivity growth driver is changes in the miscellaneous external business conditions, other than input price inflation and output growth, which affect cost. An example for a power distributor is forestation. In a suburb or rural area where forestation is increasing (due, for example, to the conversion of cropland to other uses), rising vegetation management expenses due to growing trees will cause productivity growth to slow.

System age can drive productivity growth in the short and medium term. Productivity growth tends to be greater to the extent that the capital stock is large relative to the need to replace plant that is nearing retirement age. If a utility requires unusually high replacement capital expenditures ("capex"), capital productivity growth can be unusually slow. The utility is, effectively, replacing depreciated older facilities with newer facilities that will last for many years and may be sized to accommodate future demand growth but are for these reasons more expensive.

Productivity growth is also driven by changes in X inefficiency. X inefficiency is the degree to which a company fails to operate at the maximum possible efficiency. Productivity growth will increase to the extent that X inefficiency diminishes. A company's potential for future productivity growth from this source is greater the higher is its current inefficiency.

Our analysis suggests that productivity growth can be different between utilities, and over time, for the same utility, for reasons that are beyond their control. For example, a utility with unusually slow

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[11] The seminal paper on this topic is Denny, Fuss and Waverman, *op. cit.*

[12] Incremental scale economies may also depend on the current scale of an enterprise. For example, there may be diminishing incremental returns to scale as enterprises grow.

output growth and an unusually high number of assets needing replacement can have unusually slow productivity growth.

Use of Index Research in Regulation

Revenue Cap Indexes

Cost theory and index logic support the design of revenue adjustment indexes. The following basic result of cost theory is useful.

$$growth\ Cost = growth\ Input\ Prices - growth\ Productivity^{C} + growth\ Outputs^{C}.^{13} \qquad [5]$$

The growth in the cost of a utility is the difference between the growth in its input price and cost efficiency indexes plus the trend in a consistent cost-based output index.

Assuming that growth in allowed revenue should track the growth in the cost of the typical utility, this result provides the basis for a revenue adjustment index of general form:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices - X + growth\ Scale^{C}_{Utility} \qquad [6a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + Consumer\ Dividend. \qquad [6b]$$

Here $Scale^{C}_{Utility}$ is an index of growth in the operating scale of the subject utility. X, the "X factor," reflects the base MFP growth trend ("$\overline{MFP}^{C}$") of the industry and a consumer dividend.[14] The base MFP growth trend is typically the trend in the MFP^{C} of the regional or national utility industry. Notably, a consistent cost-based scale index should be used in the supportive MFP research.

For gas and electric power distributors, the number of customers served is a sensible scale escalator for a revenue adjustment index. The customers variable typically has the highest estimated cost elasticity amongst the scale variables considered in econometric research on the cost of energy distributors. A scale escalator that includes volumes and/or peak demand as scale variables diminishes

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[13] An alternative basis for a revenue adjustment index can be found in index logic. Recall from relation [1] that the growth in the cost of an enterprise is the sum of the growth in an appropriately designed input price index and input quantity index. Then,

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices + growth\ Scale^{C} - (growth\ Scale^{C} - growth\ Input\ Quantities) \\ &= growth\ Input\ Prices - growth\ MFP^{C} + growth\ Scale^{C} \end{aligned}$$

[14] Since the X factor often includes a consumer dividend in approved MRPs, it is sometimes said that the productivity research has the goal of "calibrating" (rather than solely determining) X.

a utility's incentive to promote DSM. This is an argument for excluding these variables from a revenue adjustment index scale escalator.

The number of customers can replace $Scale^{C}_{Utility}$ in relation [6a], with the following result:

$$growth\ Revenue^{Allowed} = growth\ Input\ Prices_{Industry} - X + growth\ Customers_{Utility} \qquad [7a]$$

$$X = \overline{MFP}^{N}_{Industry} + Consumer\ Dividend.^{15} \qquad [7b]$$

where $\overline{MFP}^{N}$ is the trend in an MFP index that uses the number of customers to measure output.

The HECO Companies are vertically integrated electric utilities ("VIEUs") that provide state-regulated generation and transmission services as well as distributor services. It therefore makes sense to consider a multidimensional scale index to measure VIEU output in statistical cost research to support the design of revenue adjustment indexes for these Companies.

Inflation Issues

Suppose, now, that a macroeconomic inflation index such as the GDPPI is used as the inflation measure in a revenue adjustment index. Relation [5] can be restated as:

$$\begin{aligned} growth\ Cost &= growth\ Input\ Prices - growth\ Productivity + growth\ Outputs^{C} \\ &\quad + growth\ GDPPI - growth\ GDPPI \\ &= growth\ GDPPI - [growth\ Productivity + (growth\ GDPPI - growth\ Input\ Prices)] \\ &\quad + growth\ Outputs^{C}. \qquad [8] \end{aligned}$$

Relation [8] shows that cost growth depends on GDPPI inflation, growth in operating scale and productivity, and on the difference between GDPPI and utility input price inflation. This provides the basis for the following revenue adjustment index:

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X + growth\ Scale^{C}_{Utility} \qquad [9a]$$

where

$$X = \overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices_{Industry}}\right) + Consumer\ Dividend. \qquad [9b]$$

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15 An equivalent formula is:
$growth\ Revenue^{Allowed} - growth\ Customers = growth\ (Revenue^{Allowed}/Customer) = growth\ Input\ Prices - X.$
This is sometimes called a "revenue per customer" index.

In addition to the base productivity trend, the X factor now includes the difference between the GDPPI and industry input price trends. The second X factor term may be called the "inflation differential."[16]

Consider now that the GDPPI is the U.S. government's featured index of inflation in the prices of the economy's final goods and services.[17] It can then be shown that the trend in the GDPPI is well-approximated by the difference between the trends in the economy's input price and (multifactor) productivity indexes.

$$trend\ GDPPI = trend\ Input\ Prices_{Economy} - trend\ MFP_{Economy}. \quad [10]$$

When the GDPPI is used as the inflation measure in a revenue adjustment index, revenue growth is therefore already slowed by the MFP trend of the economy.

The formula for the X factor can then be restated as:

$$X = \overline{MFP}^{C}_{Industry} + [(\overline{Input\ Prices}_{Economy} - \overline{MFP}_{Economy}) - \overline{Input\ Prices}_{Industry}].$$

$$= [(\overline{MFP}^{C}_{Industry} - \overline{MFP}_{Economy}) + (\overline{Input\ Prices}_{Economy} - \overline{Input\ Prices}_{Industry})]. \quad [11]$$

It follows that adding an inflation differential to the X factor formula involves a reduction in X by the MFP trend of the economy. Furthermore, the X factor can be stated equivalently as the sum of a productivity differential and an input price differential. The productivity differential is the difference between the MFP trends of the industry and the economy. The input price differential is the difference between the input price trends of the economy and the industry. Relation [11] is notable because it has been the basis for the design of several approved X factors in MRPs. This approach has been especially popular in New England regulation.[18]

Regardless of whether relation [9b] or [11] are used in research to calculate the X factor, the benefit of these more complex formulations goes beyond correcting for the tendency of GDPPI to mismeasure estimated industry input price growth. Consider, for example, the trend in a revenue adjustment index that is designed in accordance with relations [9a] and [9b].[19]

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[16] It can also be shown that the X factor measures the tendency of the unit costs of sampled utilities to grow more slowly than inflation.

[17] Final goods and services include consumer products, government services, and exports.

[18] This approach has been approved in Massachusetts on several occasions. See, for example, D.P.U. 96-50, D.T.E. 03-40, D.T.E. 05-27, and D.P.U. 17-05.

[19] A similar result can be obtained using relations [9a] and [11].

$$\overline{Revenue}^{Allowed} = \overline{GDPPI} - \left[\overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices}_{Industry}\right)\right] + \overline{Scale}^{C}_{Utility}$$

$$= -\left(\overline{Scale}_{Industry} - \overline{Inputs}_{Industry} - \overline{Input\ Prices}_{Industry}\right) + \overline{Scale}^{C}_{Utility}$$

$$= \left(\overline{Input\ Prices}_{Industry} + \overline{Inputs}_{Industry}\right) + \left(\overline{Scale}_{Utility} - \overline{Scale}_{Industry}\right)$$

$$= \overline{Cost}_{Industry} + \left(\overline{Scale}_{Utility} + \overline{Scale}_{Industry}\right) \quad [12]$$

The trend in a revenue adjustment index thus equals the cost trend of the industry plus the difference in the scale trends of the utility and the industry. Any tendency of the input price index used in calculations to mismeasure input price growth is then corrected.

Scale Escalators

Revenue adjustment indexes do not always include explicit scale escalators. A revenue adjustment index of general form

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X \quad [13a]$$

is equivalent to the following:

$$growth\ Revenue^{Allowed} = growth\ GDPPI - X + growth\ Scale_{Utility} \quad [13b]$$

where

$$X = \overline{MFP}^{C}_{Industry} + \left(\overline{GDPPI} - \overline{Input\ Prices}_{Industry}\right) + Expected(growth\ Scale_{Utility})$$

$$+ \ Consumer\ Dividend. \quad [13c]$$

It can be seen that if the MFP does not otherwise compensate the utility for growth in its operating scale, the expected scale index growth of the utility is an implicit stretch factor. The value of this implicit stretch factor will be larger the more rapid is the utility's expected scale index growth.

Consumer Dividend

The consumer dividend (aka Stretch Factor) term of a rate or revenue adjustment index should reflect an expectation of how the productivity growth of the subject utility will differ from the base productivity growth target. This depends in part on how the performance incentives generated by the MRP compare to those in the regulatory systems of utilities in the productivity studies used to set the base productivity trend. It also depends on the company's operating efficiency at the start of the plan. Productivity growth should be more rapid to the extent that inefficiency is greater.

Statistical benchmarking is useful in setting stretch factors. Benchmarking can address O&M expenses, capital cost, total cost, and reliability. Sophisticated econometric cost benchmarking studies are routinely used to set stretch factors for power distributors in Ontario. Statistical cost benchmarking is also extensively used by Australian and British utility regulators.[20]

3.2 Capital Specification

Monetary Approaches to Capital Cost and Quantity Measurement

The capital cost ("CK") specification is critical in research on the input price and productivity trends of utilities because the technology of these companies is capital intensive. The annual cost of capital includes depreciation expenses, a return on investment, and certain taxes. If the price (unit value) of the asset changes over time this cost may also be net of any capital gains or losses.

Monetary approaches to the measurement of capital prices and quantities are conventionally used in research on the costs and input price and productivity trends of utilities. These approaches permit the decomposition of capital cost into a consistent capital quantity index ("*XK*") and capital price index ("*WK*") such that

$$CK = WK \cdot XK. \quad [14]$$

[21,22]

In electric utility research, capital quantity indexes are typically constructed by deflating the value of gross plant additions using a Handy Whitman electric utility construction cost index and subjecting the resultant quantity estimates to a mechanistic decay specification. Capital prices are constructed from these same construction cost indexes and from data on the rate of return on capital.[23]

[20] PEG has prepared transnational power distribution cost benchmarking studies for both the Australian Energy Regulator and the Ontario Energy Board and benchmarks the costs of all Ontario Power distributors each year using the latest available Ontario data.

[21] In rigorous statistical cost research, it is often assumed that a capital good provides a stream of services over some period of time (the "service life" of the asset). The capital *quantity* index measures this flow, while the capital *price* index measures the trend in the simulated price of renting a unit of capital service. The design of the capital service price index is consistent with the assumption about the decay in the service flow. The product of the capital service price index and the capital quantity index is interpreted as the annual cost of using the flow of services.

[22] The growth rate of capital cost then equals the sum of the growth rates of the capital price and quantity indexes.

[23] If taxes are included, capital prices are also a function of tax rates.

Alternative Monetary Approaches

Several monetary methods for measuring capital cost have been established. A key issue in the choice between some monetary methods is the pattern of decay that is assumed in the service flow from the plant additions that are made each year.[24] Another issue is whether plant is valued in historic or replacement dollars. Here are brief descriptions of the three monetary methods that have been most commonly used in the design of rate and revenue adjustment indexes.

1. Geometric Decay ("GD"). Under the GD method, the flow of services from plant additions in a given year is assumed to decline at a constant rate over time.[25] Plant is typically valued in replacement dollars. Cost is computed net of capital gains. Replacement valuation differs from the historical (a.k.a. "book") valuation used in North American utility accounting.

   The GD capital price is a simulation of the price for capital services in a competitive rental market in which the capital stocks of suppliers experience GD. The price is driven by trends in construction costs and the rate of return on capital.

2. One-Hoss-Shay ("OHS"). Under the OHS method, the flow of services from a capital asset is assumed to be constant until the end of its service life, when it abruptly falls to zero.[26] This is the pattern that is typical of an incandescent light bulb. However, in energy utility research this

[24] Decay can result from many factors including wear and tear, casualty loss, increased maintenance requirements, and technological obsolescence. The pattern of decay in assets over time is sometimes called the age-efficiency profile.

[25] The quantity of capital at the end of each period *t* ("XK_t") is related to the quantity at the end of *last* period and the quantity of gross plant additions ("XKA_t") by the following "perpetual inventory" equation:

$$\begin{aligned} XKt &= XK_{t-1} \cdot (1-d) + XKA_t \\ &= XK_{t-1} \cdot (1-d) + \frac{VKA_t}{WKA_t}. \end{aligned}$$

Here *d* is the (constant) rate of decay in the quantity of older capital. The quantity of capital added each year is calculated by dividing the reported value of gross plant additions by the contemporaneous value of a suitable asset price index ("*WKA*").

[26] The quantity of plant at the end of the year is the sum of the quantity at the end of the prior year plus the quantity of gross plant additions less the quantity of plant retirements ("XKR_t").

$$\begin{aligned} XK_t &= XK_{t-1} + XKA_t - XKR_t. \\ &= XK_{t-1} + \frac{VKA_t}{WKA_t} - \frac{VKR_t}{WKA_{t-s}}. \end{aligned}$$

Since utility retirements are valued in historical dollars, the quantity of retirements in year *t* can be calculated by dividing the reported value of retirements by the value of the asset price index for the year when the assets retired were added.

constant flow assumption has, due to data limitations, been applied to the total plant additions for groups of assets that have varied service lives. Plant is once again valued at replacement cost and cost is computed net of capital gains. As with GD, it is common to use a capital service price that is consistent with the OHS assumption.

3. Cost of Service ("COS"). The GD and OHS approaches for calculating capital cost use assumptions that are quite different from those used to calculate capital cost under traditional COS ratemaking.[27] Replacement valuation of plant, capital gains, and use of capital service prices can all give rise to volatile capital prices that complicate the identification of inflation (and input price) differentials. The derivation of a revenue adjustment index using index logic does not require a service price treatment of the capital price.

   An alternative COS approach to measuring capital cost has been developed by PEG that is so-called because it is based on the straight-line depreciation and historical plant valuations, techniques used in utility capital cost accounting. Capital cost can still be decomposed into a price and a quantity index, but the capital price cannot be represented as a capital service price. The price and quantity index formulae are complicated, making them more difficult to code and review. However, capital prices are less volatile, making the identification of sensible inflation and input price differentials easier.

Kahn Method

The Kahn method for calibrating X factors was developed by noted Cornell University regulatory economist Alfred Kahn and is used by the Federal Energy Regulatory Commission ("FERC") to set the X factors in the price cap indexes of interstate oil pipelines.[28] PEG has developed a variant of the original Kahn method which we believe is more useful in X factor research. In an application to the HECO Companies, we would calculate trends in the cost of base rate inputs of a sample of VIEUs using FERC Form 1 data and capital cost accounting like that used in Hawaii and then solve for the value of X which would have caused the trend in VIEU cost to equal the trend in a revenue adjustment index. This analysis could exclude itemized costs that are likely to be addressed by trackers and riders in the Companies' new PBR plan. The X factor resulting from such a calculation reflects the inflation differentials of sampled utilities as well as their productivity trends without having to itemize them.

[27] The OHS assumptions are more markedly different.

[28] See, for example, FERC Orders 561 and 561-A.

Stated differently, the X factor would reflect the input price and productivity differentials of utilities combined.

3.3 Application to the HECO Companies

To develop an X factor for the HECO Companies, a rigorous, thorough, and complex approach would be to use the latest available data (e.g., through 2018) from the FERC and other reputable sources to 1) develop a scale index using econometric research on VIEU cost to identify scale variables and their cost elasticities and 2) calculate the average productivity trend and inflation differential of the sampled utilities.[29] An X factor could instead be calculated using a simpler "Kahn Method" exercise.

Some special considerations are also pertinent in choosing X factors for the HECO Companies. These Companies will have trackers for costs of major plant additions. However, major plant additions typically account for less than half of each Company's capex. There may be markdowns on the capex that is otherwise eligible for tracker treatment. Moreover, the revenue adjustment indexes will not include scale escalators. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes.

[29] We could, alternatively, use the same data to calculate input price and productivity differentials consistent with relation [11].

4. Salient Precedents

This section of the report discusses precedents for energy utility rate and revenue adjustment indexes with designs that were informed by cost trend research. Most of these precedents pertain to MRPs for gas and electric power distributor services. We also review provisions for supplemental capital revenue when funding from rate and revenue adjustment indexes is otherwise expected to be insufficient.

4.1 Revenue Adjustment Indexes

Table 1 provides a summary of approved North American revenue adjustment indexes with designs that were informed by cost trend research. It can be seen that the majority have included a scale escalator. Most commonly, growth in allowed revenue equals inflation – X + customer growth. Large utilities that have operated under this general approach to revenue escalation include ATCO Gas in Alberta, Enbridge Gas Distribution in Ontario, Hydro-Québec Distribution, Southern California Edison, and Southern California Gas.[30] Utilities in other jurisdictions have had formulas like this to adjust the revenue for certain cost *components*. A plan for FortisBC, for example, has revenue adjustment indexes for O&M expenses and routine plant additions.

4.2 Inflation Measures

Table 2 provides information on the inflation measures used in approved rate and revenue adjustment indexes. It can be seen that U.S. indexes typically rely on a single macroeconomic inflation measure to make inflation adjustments. Of these, the GDPPI has been the most popular by far. This is due in part to the fact that the GDPPI is less sensitive to fluctuations in food and energy commodity prices than consumer price indexes. More customized industry-specific inflation measures have been popular in recent Canadian MRPs.

[30] The Régie de l'énergie in Québec has also ruled that the largest provincial gas utility, Énergir, will prospectively operate under such an index.

Table 1

Approved Revenue Cap Indexes Informed By Cost Trend Research[1]

Applicable Services	Utility	Jurisdiction	Plan Term	Scale Escalator(s)
Gas Distribution	Southern California Gas	California	1997-2002	Customers
Gas Distribution	BC Gas	British Columbia	1998-2000	Customers, Service Line Additions, etc.[2]
Power Distribution	Southern California Edison	California	2002-2003	Customers
Bundled Power Service and Gas Distribution	Pacific Gas and Electric	California	2004-2006	None
Gas Distribution	Southern California Gas	California	2005-2007	None
Gas Distribution	Gaziféré	Québec	2006-2010	Customers
Gas Distribution	Vermont Gas Systems	Vermont	2006-2009, extended to 2015	Customers
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Customers
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	None
Power Distribution	Green Mountain Power	Vermont	2010-2013	None
Gas Distribution	Gaziféré	Québec	2011-2015	Customers
Gas Distribution	All Distributors	Alberta	2013-2017	Customers
Bundled Power Service	FortisBC	British Columbia	2014-2019	Customers
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Customers, etc.[2]
Gas Distribution	All Distributors	Alberta	2018-2022	Customers
Power Distribution	Eversource Energy	Massachusetts	2018-2023	None
Power Distribution	Hydro-Québec	Québec	2018-2022	Customers
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	None

[1] Shaded plans have expired.

[2] There are separate revenue cap indexes for O&M expenses and various kinds of capex in these plans that in some instances have different scale escalators. For example, the annual scale escalator for services capex is the number of service additions.

Table 2

Base Productivity Trend, Consumer Dividend, and X Factor Decisions in North American PBR Proceedings[1]

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Consumer Dividend[2]	X-Factor [3,4]
Bundled Power Service	PacifiCorp (I)	California	1994-1997, extended to 1999	Price Cap	Industry-specific	1.40%	NA	1.40%
Bundled Power Service	Central Maine Power (I)	Maine	1995-1999	Price Cap	GDPPI	NA	NA	0.9% (Average)
Oil Pipelines	All U.S.	United States	1995-2001	Price Cap	PPI-Finished Goods	NA	NA	1.00%
Gas Distribution	Southern California Gas	California	1997-2002	Revenue Cap	Industry-specific	0.50%	0.80% (Average)	2.3% (Average)
Power Distribution	Southern California Edison	California	1997-2002	Price Cap	CPI	NA	NA	1.48% (Average)
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2003	Price Cap	GDPPI	0.40%	0.50%	0.50%
Power Distribution	Bangor Hydro Electric (I)	Maine	1998-2000	Price Cap	GDPPI	NA	NA	1.20%
Power Distribution	PacifiCorp (II)	Oregon	1998-2001	Revenue Cap	GDPPI	NA	NA	0.30%
Gas Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.68%	0.55% (Average)	1.23% (Average)
Power Distribution	San Diego Gas and Electric	California	1999-2002	Price Cap	Industry-specific	0.92%	0.55% (Average)	1.47% (Average)
Power Distribution	All Ontario Distributors	Ontario	2000-2003	Price Cap	Industry-specific	0.86%	0.25%	1.50%
Gas Distribution	Bangor Gas	Maine	2000-2009, extended to 2012	Price Cap	GDPPI	NA	NA	0.36% (Average)
Gas Distribution	Union Gas	Ontario	2001-2003	Price Cap	GDPPI	NA	NA	2.50%
Oil Pipelines	All U.S.	United States	2001-2006	Price Cap	PPI-Finished Goods	NA	NA	0.00%
Power Distribution	Central Maine Power (II)	Maine	2001-2007	Price Cap	GDPPI	NA	NA	2.57% (Average)
Power Distribution	Southern California Edison	California	2002-2003	Revenue Cap	CPI	NA	NA	1.60%
Power Distribution	EPCOR (I)	Alberta	2002-2005, Terminated at end of 2003	Price Cap	Industry-Specific	NA	NA	15% * Inflation
Gas Distribution	Berkshire Gas	Massachusetts	2002-2011	Price Cap	GDPPI	0.40%	1.00%	1.00%
Gas Distribution	Blackstone Gas	Massachusetts	2004-2009	Price Cap	GDPPI	NA	NA	0.50%
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, terminated in 2010	Price Cap	GDPPI	0.58%	0.30%	0.41%
Power Distribution	All Ontario Distributors	Ontario	2006-2009	Price Cap	GDP IPI Canada	NA	NA	1.00%
Oil Pipelines	All U.S.	United States	2006-2011	Price Cap	PPI-Finished Goods	NA	NA	-1.30%
Power Distribution	NSTAR	Massachusetts	2006-2012	Price Cap	GDPPI	NA	NA	0.63% (Average)
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	Price Cap	GDPPI	0.58%	0.40%	0.51%
Power Distribution	ENMAX	Alberta	2007-2013	Price Cap	Industry-specific	0.80%	0.40%	1.20%
Gas Distribution	Enbridge Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	47% x Inflation (Average)
Gas Distribution	Union Gas	Ontario	2008-2012	Revenue Cap	GDPPI	NA	NA	1.82%
Power Distribution	Central Vermont Public Service	Vermont	2009-2011, extended to 2013	Revenue Cap	CPI	1.03%	NA	1.00%
Power Distribution	Central Maine Power (III)	Maine	2009-2013	Price Cap	GDPPI	NA	NA	1.00%
Power Distribution	All Ontario Distributors	Ontario	2010-2013	Price Cap	GDPPI	0.72%	0.40% (Average Across Firms)	1.12% (Average Across Firms)
Power Distribution	Green Mountain Power	Vermont	2010-2013	Revenue Cap	CPI	NA	NA	1.00%

Table 2 (Continued)

Applicable Services	Utilities	Jurisdiction	Term	Cap Form	Inflation Measure	Acknowledged Productivity Trend	Consumer Dividend[2]	X-Factor [3,4]
Oil Pipelines	All U.S.	United States	2011-2016	Price Cap	PPI-Finished Goods	NA	NA	-2.65%
Power & Gas Distribution	All Distributors	Alberta	2013-2017	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	0.96%	0.20%	1.16%
Gas Distribution	Union Gas	Ontario	2014-2018	Revenue Cap	GDPPI	NA	NA	60% x Inflation
Power Distribution	All Distributors except those who opt out	Ontario	2014-2020	Price Cap	Industry-specific	0.00%	Range of 0% to 0.6%	Range of 0% to 0.6%
Bundled Power Service	FortisBC	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.93%	0.10%	1.03%
Gas Distribution	FortisBC Energy	British Columbia	2014-2019	Revenue Cap	Industry-specific	0.90%	0.20%	1.10%
Oil Pipelines	All U.S.	United States	2016-2021	Price Cap	PPI-Finished Goods	NA	NA	-1.23%
Hydro Power Generation	Ontario Power Generation	Ontario	2017-2021	Price Cap	Industry-specific	0.00%	0.30%	0.30%
Power & Gas Distribution	All Distributors	Alberta	2018-2022	Price Cap for Power, Revenue per Customer Cap for Gas	Industry-specific	NA	NA	0.30%
Power Distribution	Hydro-Québec	Québec	2018-2022	Revenue Cap	Industry-specific	NA	0.00%	0.30%
Power Distribution	Eversource Energy[5]	Massachusetts	2018-2023	Revenue Cap	GDPPI	-0.46%	0.25% if GDPPI growth exceeds 2%	-1.31%
Gas Distribution	Amalco	Ontario	2019-2023	Price Cap	GDPPI	0.00%	0.30%	0.30%
Power Transmission	Hydro One Sault Ste. Marie	Ontario	2019-2026	Revenue Cap	Industry-specific	0.00%	0.30%	0.30%

		Acknowledged Productivity Trend	Consumer Dividend	X-Factor
Averages*	**All Current and Expired Plans**	**0.56%**	**0.37%**	**0.73%**
	All Current Plans	**0.20%**	**0.22%**	**0.14%**
	All Current Canadian Plans	**0.31%**	**0.21%**	**0.49%**
	All Current U.S. Plans	**-0.46%**	**0.25%**	**-1.27%**

*Averages exclude X factors that are percentages of inflation.

[1] Shaded plans have expired.

[2] Some approved X factors are not explicitly constructed from such components as a base productivity trend and a consumer dividend. Many of these are the outcome of settlements.

[3] X factors may not be the sum of the acknowledged productivity trend and the consumer dividend, where these are itemized, for reasons that include the following: (1) a macroeconomic inflation measure is employed in the attrition relief mechanism or (2) the X factor may incorporate additional adjustments to account for special business conditions.

[4] North American X factors typically include any consumer dividend that has been explicitly or implicitly approved.

[5] The approved X factor for Eversource Energy did not include the consumer dividend. To ensure consistency across examples, we have recalculated the X factor here, assuming that the 0.25% consumer dividend will be applied in all years.

4.3 Productivity Differentials

Table 3 documents instances in which regulators have reduced X factors by the MFP trend of the national economy when a macroeconomic inflation measure was used in a rate or revenue cap index. We noted in Section 3.1 that this is typically done with an explicit productivity differential term in the X factor formula. Table 3 includes *all* known instances of an explicit productivity differential in approved X factors for *energy* utilities along with a *sampling* of the analogous adjustments in indexes for *telecommunications* ("telecom") utilities. We believe that there are many more instances of productivity differentials in approved telecom-utility X factors.

Table 3

Precedents for Productivity Differentials in the Calculation of Approved X Factors

Applicable Services	Company	Jurisdiction	Plan Term	Inflation Measure	Case Reference
Energy					
Power Distribution	Eversource Energy	Massachusetts	2018-2022	GDPPI	DPU 17-05; November 2017
Gas Distribution	Bay State Gas	Massachusetts	2006-2015, terminated in 2009	GDPPI	Docket DTE 05-27
Gas Distribution	Boston Gas (I)	Massachusetts	1997-2001	GDPPI	Docket D.P.U. 96-50-C (Phase I); May 1997
Gas Distribution	Boston Gas (II)	Massachusetts	2004-2013, Terminated in 2010	GDPPI	Docket DTE 03-40
Gas Distribution	Union Gas	Ontario, Canada	2001-2003	GDP IPI Canada	RP-1999-0017; July 2001
Power Transmission & Distribution	Power & Water	Australia - Northern Territory	2009-2014	CPI Australia	Final Determination Networks Pricing: 2009 Regulatory Reset; March 2009
Bundled Power Service	Jamaica Public Service	Jamaica	2015-2019	CPI Jamaica adjusted for U.S. inflation	Jamaica Public Service Company Limited Tariff Review for Period 2014-2019 Determination Notice
Power Distribution	All	New Zealand	2004-2009	CPI New Zealand	Commerce Commission Regulation of Electricity Lines Businesses, Targeted Control Regime, Threshold Decisions; December 2003
Power Distribution	All	New Zealand	2010-2015	CPI New Zealand	Commerce Commission Initial Reset of the Default Price-Quality Path for Electricity Distribution Businesses Decisions Paper; November 2009
Telecommunications					
Telecom	SNET	Connecticut	1996-2001	GDPPI	Docket 95-03-01
Telecom	Ameritech	Illinois	1995-2002	GDPPI	Case 92-0048/93-0239
Telecom	NYNEX	Massachusetts	1995-2001	GDPPI	D.P.U. 94-50
Telecom	Interstate access services of LECs	US National	1997-2000	GDPPI	Docket 97-159
Telecom	BC Tel, Bell Canada, Island Tel, MTT, MTS, NB Tel, TELUS	Canada National	1998-2001	GDPPI	CRTC 97-9
Telecom	NYNEX	New York	1995-1999	GDPPI	Case 92-G-0665

4.4 Kahn Method

The FERC has approved Kahn method X factors for the price cap indexes of interstate oil pipelines five times. The current Oil Pipeline Index escalates prices by the Producer Price Index ("PPI") for Finished Goods plus 1.23%, indicating an X factor of -1.23%.[31] The prior index escalated prices by the PPI for Finished Goods plus 2.65%, indicating an X factor of -2.65%.[32] The Régie de l'énergie in Quebec recently relied on the Kahn method in part to set the X factor of a revenue cap index for the O&M expenses of Hydro Quebec Transmission.[33]

4.5 Base Productivity Trends, Consumer Dividends, and X Factors

Table 2 and Figures 1 and 2 provide summaries of the explicit base productivity trends, consumer dividends, and X factors in energy utility rate and revenue cap indexes that have been approved by North American regulators and informed by cost trend research. The following results are notable.

- The base productivity trends and consumer dividends have fallen over the years. The average of the acknowledged base productivity trends in current plans is 0.20%. The Ontario Energy Board has approved 0% base productivity trends on several recent occasions. The Massachusetts Department of Public Utilities ("DPU") recently acknowledged a -0.46% productivity trend for U.S. power distributors. The average of the approved consumer dividends in current plans is 0.22%.
- X factors have also trended downward over time. The average X factor in current plans is 0.14%. The current -1.27% average for U.S. plans is well below the current 0.49% average for Canadian plans.
- The X factors reported in Table 2 are inclusive of any approved consumer dividends, whereas Hawaii's PUC has decided to have a separate consumer dividend. The average current X factor exclusive of any explicitly-approved consumer dividend is about -0.04%. The average for U.S. plans is -1.40% whereas the average for Canadian plans is about 0.30%.

[31] FERC (2015), *Order Establishing Index Level*, FERC Docket No. RM15-20-000, December.

[32] FERC (2010), *Order Establishing Index for Oil Price Change Ceiling Levels*, FERC Docket No. RM10-25-000, December.

[33] Régie de l'énergie (2019), Decision 2019-060, R-4058-2018, May, p. 35-36.

Figure 1

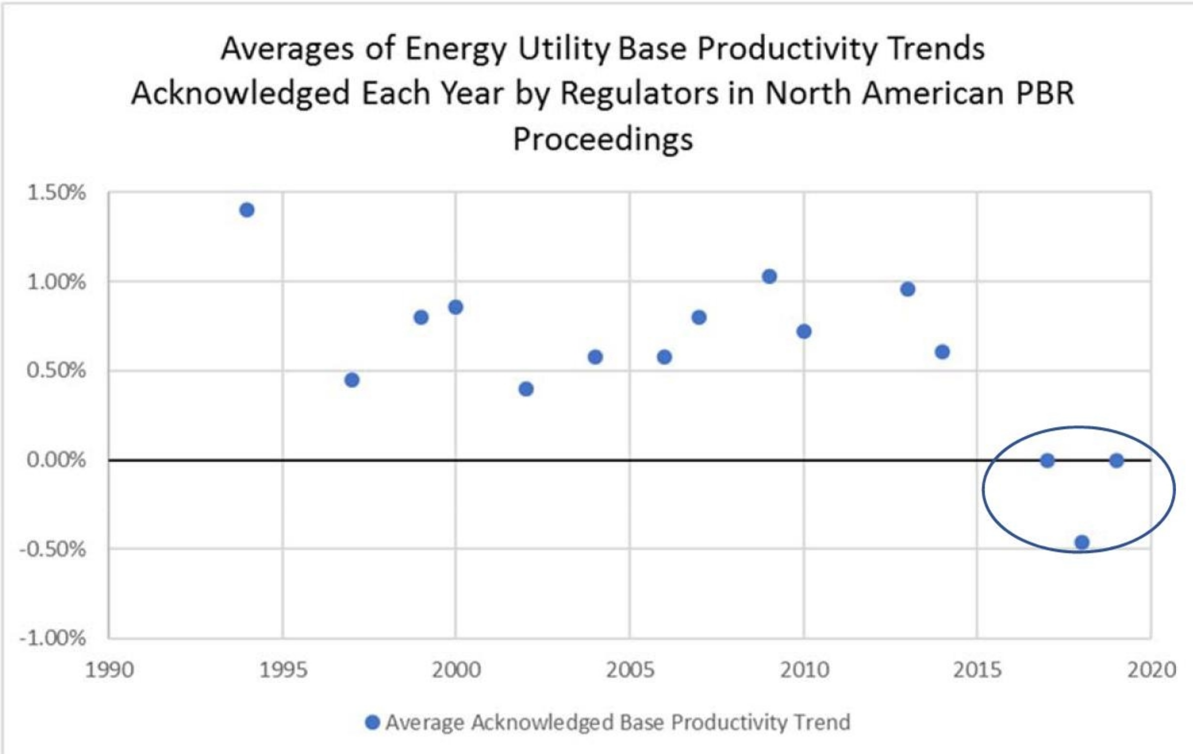
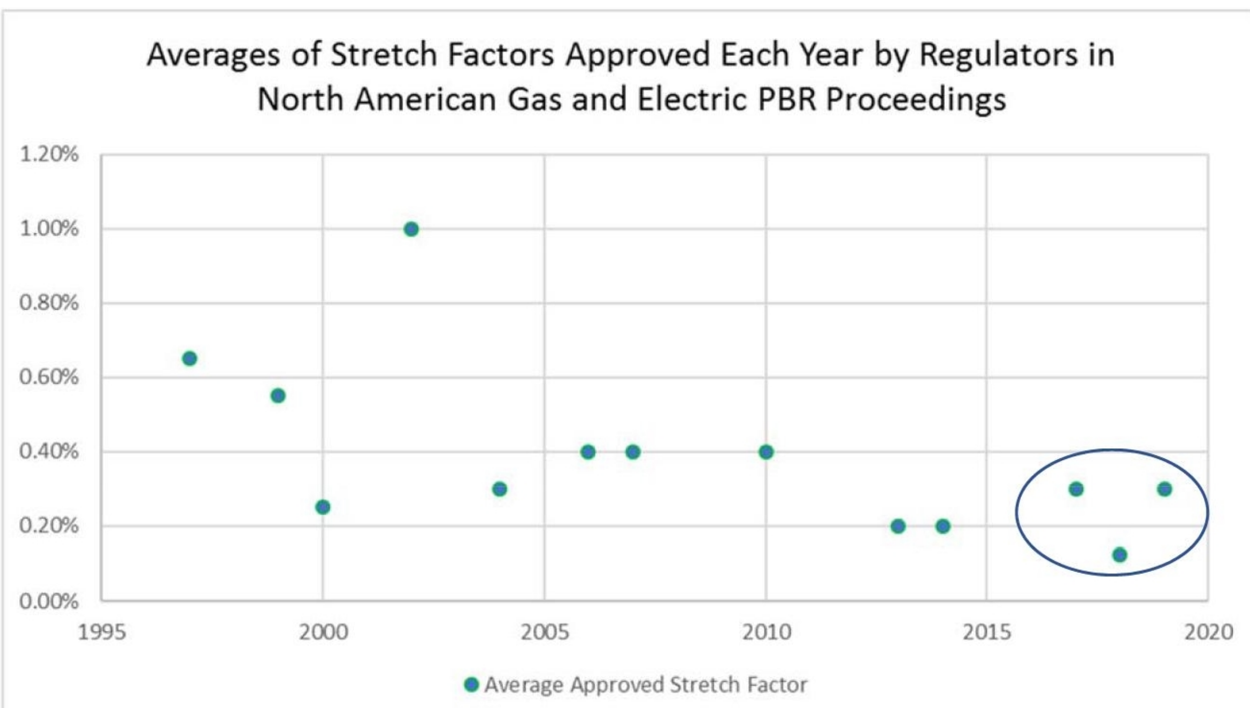


Figure 2



4.6 Making Sense of Negative X Factors for Energy Distributors

The tendency of X factors to be lower in the United States than in Canada and to be trending negative under current business conditions merits some explanation. We noted above that base productivity growth rates acknowledged by regulators have been trending downward. Most of the studies that inform these decisions pertain to energy distributors. Reasons for declines in the acknowledged MFP growth trends of energy distributors include the following.

- Growth in the number of customers served and system use has been slowed by sluggish economic growth since the Great Recession of 2008. Growth in system use (e.g., peak load) has also been slowed by expanded demand-side management ("DSM") programs. Slow growth in customers and system use reduces opportunities for distributors to increase capacity utilization and realize incremental scale economies. Utilities must still incur the costs of owning, operating, and maintaining capacity that was built in an era of more optimistic demand growth projections. Less important but notable is the related fact that slow growth in the number of *gas* customers served by combined gas and electric utilities has reduced opportunities to realize incremental economies of *scope* from the shared use of certain inputs (e.g., in billing and collection).

- Some distributors have made sizable investments in facilities that create benefits that are not captured by the output indexes commonly used to measure energy distributor productivity. For example, some distributors have been asked by their regulators to improve system reliability and/or resiliency. In the last ten years particularly, many distributors have added automated metering infrastructure ("AMI") that can reduce the duration of outages and facilitate peak load management.

- In a few states, such as Hawaii and California, growth in distributed generation ("DG") on the customer side of the meter has challenged distributors to handle intermittent DG power surpluses and honor highly volatile requests for power deliveries from the grid. Peak loads may still be quite high.

- Some utilities are accelerating replacement of distribution plant approaching retirement age. Long-term costs are often reduced by choosing replacement assets with lengthy service lives, and by sizing these facilities so that they can handle some future demand growth. These assets thus are typically much more costly to own than the highly-

depreciated assets that they replace. For replacement capex and smart grid facilities alike, the impact on distributor revenue requirements is magnified by the historical cost accounting that is commonly used for capital assets in North American rate regulation.

In the United States, low X factors are also encouraged by the tendency, noted in Section 4.2 above, to use macroeconomic inflation indexes such as the GDPPI as the sole basis for the inflation factors in rate and revenue adjustment indexes. As explained in Section 3.1, the X factor should in this case reflect the difference between the GDPPI and utility input price trends. Growth in the cost of constructing power distribution facilities was unusually rapid from 2004 to 2008, and has not been offset by a subsequent period of unusually slow construction cost growth.

GDPPI growth is slowed by the MFP growth trend of the economy, and this has prompted regulators to reduce the X factor by this trend on numerous occasions. Table 4 shows that the MFP trend of the U.S. economy has averaged a substantial 0.94% annual growth between 1997 and 2017. This compares to 0.20% average annual MFP growth in Canada for the same timeframe.

An example of a negative X factor in a U.S. plan is that recently approved by the Massachusetts Department of Public Utilities for power distributor services of Eversource.[34] The Department stated in its decision that

> In the context of a PBR, a productivity offset, or X factor, is the difference between the differential in expected productivity growth between the electric-distribution industry and the overall economy and the differential in expected input price growth between the overall economy and the electric distribution industry.[35]

and that

> The Attorney General notes that no other jurisdiction in North America has approved a negative X factor to date. This fact does not, however, preclude the possibility of an X factor that is negative. In fact, other jurisdictions have acknowledged that an X factor may be positive or negative. Whether an X factor is positive or negative is determined solely by the relationship between outputs and inputs in a given industry, and there is no reason to dismiss the possibility that the electric distribution industry may be in a period exhibiting

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[34] The operations to which this MRP applies were previously performed by Boston Edison, Western Massachusetts Electric, and Cambridge Electric Light.

[35] Massachusetts D.P.U. 17-05, "Order Establishing Eversource's Revenue Requirement," November 30, 2017, p. 381.

Table 4

MFP Trends of the U.S. and Canadian Economies

Year	United States MFP[1]	United States Growth Rate	Canada MFP[2]	Canada Growth Rate
1961	56.05		79.48	
1962	58.09	3.57%	82.07	3.21%
1963	59.78	2.87%	84.07	2.41%
1964	62.11	3.82%	85.93	2.19%
1965	64.12	3.18%	87.12	1.38%
1966	66.07	3.00%	87.44	0.37%
1967	66.13	0.09%	85.86	-1.82%
1968	67.79	2.47%	88.99	3.58%
1969	67.52	-0.40%	90.49	1.67%
1970	67.35	-0.25%	91.44	1.04%
1971	69.45	3.07%	92.24	0.87%
1972	71.42	2.81%	94.07	1.96%
1973	73.38	2.70%	95.10	1.09%
1974	70.83	-3.54%	93.85	-1.33%
1975	71.47	0.90%	93.40	-0.48%
1976	74.06	3.56%	97.06	3.85%
1977	75.32	1.69%	98.89	1.87%
1978	76.41	1.43%	99.25	0.36%
1979	75.85	-0.73%	97.91	-1.36%
1980	74.11	-2.33%	95.90	-2.07%
1981	74.37	0.35%	96.24	0.35%
1982	72.10	-3.10%	94.99	-1.30%
1983	74.16	2.82%	96.67	1.75%
1984	76.29	2.84%	99.82	3.20%
1985	77.26	1.26%	101.28	1.46%
1986	78.52	1.62%	99.89	-1.38%
1987	78.65	0.17%	100.12	0.22%
1988	79.28	0.80%	100.26	0.14%
1989	79.58	0.38%	99.26	-1.00%
1990	79.90	0.40%	97.65	-1.63%
1991	79.57	-0.41%	94.87	-2.89%
1992	82.03	3.04%	95.52	0.68%
1993	81.70	-0.40%	96.45	0.97%
1994	82.11	0.50%	98.98	2.59%
1995	82.07	-0.05%	99.23	0.25%
1996	83.16	1.32%	98.25	-1.00%
1997	84.04	1.05%	99.27	1.03%
1998	85.32	1.51%	99.95	0.68%
1999	87.20	2.18%	102.43	2.46%
2000	88.66	1.66%	104.81	2.30%
2001	89.20	0.61%	104.73	-0.08%
2002	91.04	2.04%	105.83	1.05%
2003	93.36	2.51%	105.17	-0.63%
2004	95.52	2.29%	104.88	-0.27%
2005	96.98	1.51%	104.82	-0.06%
2006	97.43	0.46%	103.87	-0.91%
2007	97.90	0.48%	102.67	-1.16%
2008	96.81	-1.13%	100.23	-2.41%
2009	97.20	0.40%	97.54	-2.72%
2010	99.70	2.55%	99.02	1.51%
2011	99.44	-0.27%	100.43	1.41%
2012	100.00	0.57%	100.00	-0.43%
2013	100.36	0.36%	100.90	0.89%
2014	100.78	0.42%	102.49	1.56%
2015	101.66	0.86%	101.46	-1.01%
2016	101.10	-0.55%	101.42	-0.04%
2017	101.48	0.37%	103.31	1.85%
2018	102.48	0.98%		
Average Annual Growth Rates				
1962-1996		**1.13%**		**0.61%**
1998-2017		**0.94%**		**0.20%**
1999-2018		**0.92%**		**NA**
2008-2017		**0.36%**		**0.06%**
2004-2018		**0.62%**		**NA**
2009-2018		**0.57%**		**NA**

[1] Net Multifactor Productivity and Cost, Private Business Sector (Excluding Government Enterprises), Bureau of Labor Statistics, March 21, 2019, Office of Productivity and Technology, Division of Major Sector Productivity

[2] Statistics Canada. Table 36-10-0208-01, Multifactor productivity, value-added, capital input and labour input in the aggregate business sector and major sub-sectors, by industry

> changes that result in decreasing output given a similar or increasing level of inputs.[36]

The Department acknowledged a productivity differential of -1.35% and an input price differential of -1.29%. A witness for a consumer advocate also supported a negative X factor despite his finding of a positive industry MFP trend.

Negative X factors have also been approved by energy utility regulators in Britain and Australia. In both countries, revenue adjustment indexes have hybrid designs in which an inflation-X formula is used but X reflects multiyear cost and inflation forecasts. One example is found in the 2006 British Transmission Price Control Review Final Proposals. Ofgem approved an Inflation + 2% price control for electric transmission utilities "to ensure that revenues, and associated cash flows are aligned more closely to the rising trend of costs resulting from the substantial increase in investment envisaged over the 5-year period."[37]

The Brattle Group's report, presented as Exhibit 2 to the HECO Companies' January 4th brief in Phase 1 of this proceeding, outlined several recent revenue cap precedents for Australian and British power distributors.[38] The authors reported that the current MRPs for all five power distributors in the populous state of Victoria, Australia allowed annual increases in authorized revenues in excess of inflation, and that these averaged 1.8%. The Brattle Group also found that in the most recently completed round of MRPs for British power distributors, 13 of 14 distributors had allowed revenue growth in excess of inflation. Real revenue increases for British power distributors averaged nearly 6% annually.

The Brattle Group's report also discussed the recent revenue requirement trends of the three large California energy utilities. They found that for the 2007-2018 period, authorized base revenues for these utilities increased 2.5% more rapidly than the growth in the GDPPI on average.[39]

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[36] *Ibid*., p. 382.

[37] Ofgem, *Transmission Price Control Review Final Proposals*, December 4, 2006, p. 7.

[38] Toby Brown and William Zarakas (2019), "*Improving the PBR Framework in Hawai'i Addressing the Risk of 'Capex Bias.'*" p. 9.

[39] *Ibid*., p. 10.

4.7 Provisions for Supplemental Capital Revenue

Our discussion of the drivers of productivity growth in Section 3.1 suggests that utilities can have expected productivity growth during an MRP which falls short of the industry norm due to adverse circumstances that are beyond their control. These circumstances include unusually slow demand growth and an unusually large need to replace plant. Regulators in several jurisdictions have recognized this problem and approved mechanisms to provide supplemental capital revenue when rate and revenue adjustment indexes are not expected to fully fund plant additions during the term of an MRP. We discuss here recent precedents from three Canadian jurisdictions.

Ontario

The Ontario Energy Board ("OEB") regulates more than 60 power distributors today. Most of these operate under MRPs called incentive regulation mechanisms ("IRMs"). In these plans, rates are initially set based on rate cases with forward test years. Distribution system plans ("DSPs") are filed. Rates in later plan years are escalated by price cap indexes with I-X formulas. The X factor for each utility is the sum of a common base productivity trend and a custom stretch factor that reflects the results of an econometric benchmarking study that is updated annually. The base productivity trend is the historical MFP trend of a power distributor peer group.

Distributors have several options for obtaining supplemental capital revenue. One option is capital modules. There are two types of capital modules available: Advanced Capital Modules ("ACMs") and Incremental Capital Modules ("ICMs"). An ACM may be requested only during rate cases to address projects outlined in the distributor's DSP, while an ICM may be requested between rate cases to address projects not included in a distributor's DSP, projects which have increased substantially in size and/or scope since the approval of the DSP, and projects whose eligibility could not be determined during the rate case.

For either type of capital module, distributors must demonstrate that the capex driving the supplemental funding request is eligible, prudently incurred, material, and the most cost-effective option for ratepayers. Distributors overearning by more than 300 basis points cannot request a capital module.

The amount of capex needed must exceed a materiality threshold defined by the OEB and must clearly have a significant influence on the operation of the distributor. The threshold has a markdown

factor. If a project qualifies for a capital module, recovery of the annual cost of the eligible plant additions is realized via rate riders. Distributors who receive approval for rate relief through a capital module are required to report their plant additions annually. Underspends will result in refunds to ratepayers. Overspends are reviewed for prudence in rate rebasing proceedings. If the overrun is prudently incurred, the amount will be included in rates.

Ontario distributors can also request a Custom Incentive Rate-setting ("Custom IR") plan. This option is designed for distributors that expect to undertake large capital projects lasting several years. This option allows distributors to develop rate or revenue cap indexes based on forecasts of total O&M and capital spending. These forecasts should be informed by the OEB-sponsored productivity and benchmarking analyses. In several cases, this has taken the form of the distributor proposing a rate or revenue adjustment index with the following escalation formula:

$$I - X + C.$$

Here the term C, called the "C factor", is the supplemental annual rate or revenue growth (as applicable) needed to fund proposed capital cost growth. X is fixed for the plan term as the sum of the approved base productivity trend and a stretch factor supported by benchmarking evidence. The growth in the revenue requirement for capex is, effectively, the growth in proposed capital cost less the X factor.

To allay concerns of distributors overestimating cost and capex, Custom IR plans have in several instances included earnings sharing mechanisms and mechanisms to return the revenue requirement impact of cumulative capex underspends to customers during rate rebasing proceedings at the end of the plan term. In its most recent decision approving a Custom IR plan for Hydro One Networks' distribution services, the OEB also adopted an additional 0.15% stretch factor to apply solely to the C term beyond the stretch factor applied to the entire revenue requirement.

British Columbia

In 2014 the British Columbia Utilities Commission ("BCUC") approved a return to MRPs for FortisBC Energy (formerly Terasen Gas) and FortisBC (formerly West Kootenay Power) after several years of more traditional regulation. Unlike MRPs in many jurisdictions, these plans escalate budgets for O&M expenses and certain plant additions with separate formulas that are based on inflation and the growth of operating scale less an X factor. The FortisBC plan has one formula for capex which features the number of customers as the scale escalator. FortisBC Energy has one formula for growth-related

capex and a second formula for sustainment and other capex. These formulas use the service line additions and the number of customers, respectively, as the scale escalators.

All of these index formulas are designed to escalate the allowed capex of projects that are smaller, more routine, and predictable. Capital costs for projects that are larger, more unusual in nature, and less predictable are tracked, along with the cost of all older plant. Projects that have been approved for capital cost tracking to date include FortisBC Energy's biomethane projects, FortisBC's deployment of AMI, and both companies' capitalized pensions and other post-employment benefits.

A substantial effort was undertaken in BC to determine tracker eligibility criteria for capex.[40] This effort extended beyond the initial PBR proceeding with a decision reached in 2015, more than a year after the PBR plan started. The BCUC approved materiality thresholds for levels of eligible capex based on the updated Certificate of Public Convenience and Necessity materiality thresholds of $20 million for FortisBC and $15 million for FortisBC Energy for individual projects.[41] The BCUC rejected proposals for additional tracker eligibility criteria.

This decision also addressed several concerns about possible gaming and double counting issues. The companies are required to show in each capital tracker application that the eligibility criteria had not been met by a combination of smaller projects that would normally be funded by the index-based escalators. Individual application proceedings will include an opportunity for the impact of the project on O&M expenses to be considered.

Alberta

Most Alberta energy distributors have operated under MRPs with rate or revenue adjustment indexes since 2013. The Alberta Utilities Commission has developed two generations of MRPs in generic proceedings. In these plans, rates or (for gas distributors) revenues per customer are escalated by indexes with I-X formulas. The X factor for each distributor is the sum of a common base productivity trend and stretch factor. Concerns about ensuring that the distributors have sufficient funding for capex have led to provisions for supplemental funding in both generations of MRPs approved to date.

The current MRPs allow for two methods by which distributors may obtain supplemental funding based on the kind of capex. Capital cost trackers may be requested to provide supplemental

[40] The BCUC refers to these criteria as capital exclusion criteria, meaning exclusion from formulaic escalators.
[41] FortisBC Energy's biomethane projects were not required to meet this threshold in order to have the projects' costs tracked.

funding for eligible capex of a type that is required by a third party and extraordinary and not previously included in the distributor's rate base.[42] Distributors must also show that this capex resulted in a revenue requirement impact that exceeded a materiality threshold of 4 basis points of ROE.

Supplemental funding for all other eligible capex is provided by a mechanism known as the K-bar. A base K-bar value was established for each distributor for the first year of the plan based on its recent *historical* capex levels, adjusted for growth in inflation, X, and billing determinant growth, which were not funded by base rates. K-bar values in subsequent years have been escalated by the growth in the attrition relief mechanism and billing determinants.

[42] In the first generation of PBR plans, capital cost trackers were the sole means by which a distributor could obtain supplemental funding for eligible capex.

5. Empirical Research for HECO

Our review of rate and revenue adjustment index precedents in Section 4 reveals that few pertain to vertically-integrated electric utilities like the HECO Companies. Moreover, the HECO Companies face special operating conditions that may affect the appropriate design of their revenue adjustment indexes. For example, an unusually large and growing share of HECO's customers own distributed photovoltaic generation facilities and HECO's generation, transmission, and distribution facilities must handle their power surpluses and accommodate large diurnal swings in their demand for power deliveries.

HECO retained PEG to undertake preliminary statistical cost research to support the design of custom revenue adjustment indexes in Phase 1 of this proceeding. Results of this research were presented in reports attached to two of the Companies' Phase 1 submissions.[43] We present in this section of the report the results of some further empirical research that we have undertaken since the Commission's Phase 1 decision.

5.1 Data

The primary source of the cost and quantity data for our empirical research in this proceeding has been FERC Form 1. Selected FERC Form 1 data were for many years published by the U.S. Energy Information Administration ("EIA").[44] More recently, the data have been available electronically from the FERC and in more processed forms from commercial vendors. The FERC Form 1 data used in this study were obtained directly from government agencies and processed by PEG. Customer data were drawn from FERC Form 1 in the early years of the sample period and from Form EIA-861 (the *Annual Electric Power Industry Report*) in later years.

Data were eligible for inclusion in our sample from all investor-owned electric utilities in the United States that provide generation, transmission, and distribution services sufficient to meet most local requirements and that, together with any important predecessor companies, have reported the necessary data continuously since 1964 (the benchmark year for our capital cost research). To be

[43] Hawaii PUC, Proceeding 2018-0088, "*Metrics Brief of the Hawaiian Electric Companies*," Exhibit 1, "*Regulatory Reform for the Hawaiian Electric Companies*," filed January 4, 2019 and "*Statement of Position of the Hawaiian Electric Companies,*" Exhibit B, "*Response to Staff Discussion on the Revenue Cap Index,*" filed March 8, 2019.

[44] This publication series had several titles over the years. A recent title is Financial Statistics of Major U.S. Investor-Owned Electric Utilities.

included in the PEG study, the data also were required to be of good quality, plausible, and free of special processing complications. Data from 45 utilities which met these standards were used in our research. We believe that these data are useful for statistical research to design revenue adjustment indexes for VIEUs. Table 5 lists the utilities from which PEG's sample were drawn.

5.2 Sample Period

The full sample period for our research was 1997-2017 for the Kahn and input price research and 1996-2017 for the econometric research. This sample permits the calculation of cost trend growth rates from 1997 to 2017. Data for 2018 are now available, and we may update our results later in the proceeding to reflect them.

5.3 Costs

The total cost of VIEU services considered in our study was the sum of applicable capital costs and O&M expenses. Costs were excluded from the research for various reasons. Some costs are not incurred by the HECO Companies or are expected to be addressed by trackers in the MRPs. We excluded the following costs from our calculations on these grounds:

- Generation fuels and other power supply inputs that include purchased power
- Other nuclear and all hydroelectric generation inputs
- Pensions and other benefits
- Taxes and franchise fees.

We excluded load dispatching, transmission by others, and miscellaneous transmission expenses out of a concern that the trend in these costs has been affected by the establishment of independent system operators in some regions of the U.S.[45] Customer service and information expenses were excluded out of a concern that, for many sampled utilities, these costs have become bloated with large DSM expenses that HECO does not incur. Utilities report administrative and general expenses, general plant costs, and amortization expenses on a consolidated basis. Since we excluded costs of some operations (e.g., nuclear generation) from the study, we included sensible *shares* of these consolidated costs rather than the entirety of these costs from the econometric and Kahn method research.

[45] These operators may also take the form of regional transmission organizations.

Table 5

Sample of Utilities Used in Empirical Research

Alabama Power	Louisville Gas & Electric
ALLETE (Minnesota Power)	MDU Resources Group
Appalachian Power	MidAmerican Energy Company
Arizona Public Service	Mississippi Power
Avista	Monongahela Power
Black Hills Power	Nevada Power
Cleco Power	Northern States Power - MN
Duke Energy Carolinas	Oklahoma Gas & Electric
Duke Energy Florida	Otter Tail Power
Duke Energy Indiana	PacifiCorp
Duke Energy Progress	Public Service Company of Colorado
El Paso Electric	Public Service Company of Oklahoma
Empire District Electric	Puget Sound Energy
Entergy Arkansas	South Carolina Electric & Gas
Entergy Mississippi	Southern Indiana Gas & Electric
Entergy New Orleans	Southwestern Electric Power
Florida Power & Light	Southwestern Public Service
Gulf Power	Tampa Electric
Idaho Power	Tucson Electric Power
Indiana Michigan Power	Union Electric
Kansas City Power & Light	Virginia Electric & Power
Kansas Gas & Electric	Westar Energy (KPL)
Kentucky Utilities	

Total of 45 VIEUs

In our econometric and input price research we employed monetary approaches to capital cost and price measurement. This permitted a decomposition of capital cost into price and quantity indexes. A geometric decay approach was used in the econometric research. We used this specification in our previous econometric and total cost research for the HECO Companies.[46] A COS approach was used in the input price research. Further details of PEG's capital cost calculations are provided in Appendix Section A.1.

[46] Lowry, M.N. and Hovde, D., "Price Cap Index Calibration for Hawaiian Electric Company, Hawaii PUC Docket 99-0396, December 13, 1999.

5.4 Input Prices

Operation & Maintenance

Occupational Employment Statistics ("OES") survey data from the Bureau of Labor Statistics ("BLS") for 2008 were used to construct averages of the salary and wage levels for numerous occupations in the service territory of each sampled utility. We used weights that correspond to the electric utility industry. Values of each company's labor price index for other years were calculated by adjusting the level in 2008 for changes in regionalized indexes of employment cost trends for the utilities sector of the economy. These indexes were constructed from BLS Employment Cost Indexes. M&S prices were escalated by the GDPPI. Summary O&M input price indexes were calculated for each utility by combining the labor and M&S price subindexes using company-specific, time-varying cost share weights. The cost shares were calculated from the FERC Form 1 data.

Capital

For the input price and econometric research, construction cost indexes and rates of return on capital are needed in the calculation of capital prices. PEG calculated weighted averages of rates of return for debt and equity.[47] We computed for each sample year a 50/50 average of the embedded average interest rate on long-term debt as calculated from FERC Form 1 data, and the average allowed rate of return on equity ("ROE") approved in electric utility rate cases as reported by the Edison Electric Institute.[48]

We calculated an index of market construction costs that was allowed to vary between the service territories of sampled VIEUs in 2008 in proportion to the relative cost of local construction as measured by the total (material and installation) City Cost Indexes published in RSMeans.[49] The market construction cost index values for other years of the sample period were determined for each company

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[47] This calculation was made solely for the purpose of measuring productivity trends and does not prescribe appropriate rate of return *levels* for utilities.

[48] The Edison Electric Institute is the principal trade association of U.S. electric utilities. The ROE data we used in the study were drawn from the backup data to the *EEI Rate Case Summary* quarterly reports.

[49] RSMeans, *Heavy Construction Cost Data 2010*.

using the rates of inflation in the appropriate regional Handy Whitman electric utility construction cost index.[50]

Multifactor Input Price Index

The summary *multifactor* input price index for each U.S. utility in our sample was constructed by combining the capital and summary O&M price indexes using company-specific, time-varying cost share weights. The cost shares were calculated from the FERC Form 1 data.

5.5 Development of a Scale Index

Our first empirical task after assembling the dataset was to develop scale indexes for each sampled utility. Recall from Section 3 that multidimensional scale indexes with cost elasticity weights can be developed for vertically-integrated electric utilities like the HECO Companies. We estimated the parameters of an econometric model of the total applicable cost of VIEU base rate inputs.[51] [52]

The values of cost and all business condition variables in this cost model were logged. This means that the estimates of the parameters for these variables were also estimates of the elasticities of cost with respect to a small change in their value. The estimation was undertaken with the R statistical programming software using a procedure that corrected for autocorrelation and groupwise heteroscedasticity.

Results of this research can be found in Table 6. It can be seen that there are nine business condition variables with statistically significant and plausibly-signed parameter estimates. These include the following five scale variables which have positive parameter estimates.

- Number of retail customers
- Generation volume
- Mid-year generation capacity
- Mid-year transmission line miles

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[50] Whitman, Requardt and Associates, *Handy-Whitman Index of Public Utility Construction Costs* (Baltimore Whitman, Requardt and Associates, various issues).

[51] By total applicable cost we mean total cost less the costs that we excluded.

[52] In this exercise, total cost was divided by the input price index to enforce a prediction of economic theory that 1% growth in the prices of all inputs raises cost by 1%. This is thus a "real" cost model.

Table 6

Econometric Model of VIEU Total Cost

Explanatory Variable	Estimated Cost Elasticity	T-Statistic	P-Value
Number of Customers	0.374	15.358 ***	0.000
Fossil Steam and Other Generation Volume	0.073	5.997 ***	0.000
Mid-Year Generation Capacity	0.212	12.329 ***	0.000
Mid-Year Transmission Line Miles	0.086	10.170 ***	0.000
Ratcheted Maximum Peak Demand	0.170	7.050 ***	0.000
Percentage of Capacity Scrubbed	0.121	11.762 ***	0.000
Percentage of Coal Capacity or Heavy Fuel Oil	0.263	12.859 ***	0.000
Percentage of Customers with AMI	0.046	3.461 ***	0.001
Number of Gas Customers	-0.016	-1.201 *	0.230
Constant	20.098	1198.599 ***	0.000
Trend	0.001	1.304 *	0.193
Adjusted R-squared	0.952		
Sample Period	1996-2017		
Number of Observations	990		

*Estimate is significant at the 75% confidence level
**Estimate is significant at the 95% confidence level
***Estimate is significant at the 99.9% confidence level

- Ratcheted annual maximum peak demand[53]

We also found that the cost of the sampled VIEUs was significantly higher

- the greater was the percentage of included generating capacity with facilities to scrub emissions for sulfur
- the greater was the percentage of generating capacity fueled by coal or heavy fuel oil
- the higher was the percentage of retail customers with AMI
- the lower was the number of gas customers served.

Notice also the 0.001 estimate of the trend variable parameter. This indicates that cost tended to rise by 0.1% annually from 1996 to 2017 for reasons that are not explained by the model's other variables.

Table 7 shows how the econometric elasticity estimates were used to calculate scale index weights for the five scale variables. It can be seen that cost was much more elastic with respect to the number of customers served , generation capacity, and ratcheted peak demand than it was with respect to the other two scale variables. The number of customers has a 40.9% weight in the scale index whereas generation capacity has a 23.2% weight and peak demand had an 18.6% weight. Generation volume has a weight around 7.9% and transmission line miles has a 9.4% weight.

5.6 Calculating an X for VIEUs Using the Kahn Method

To calculate an X factor for VIEUs using the Kahn Method we postulated a hypothetical generic revenue adjustment index with the following formula:

$$Growth\ Revenue^{Allowed} = growth\ GDPPI - X + growth\ Scale^{C}_{Utility}.$$ [54]

The scale indexes used the five scale variables and elasticity weights discussed above. We also considered an alternative and simpler scale escalator that used only the number of customers as the scale variable.

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[53] The term ratcheted peak demand means that the value of the variable equals the highest monthly peak demand that has yet been attained during the sample period. This variable is a reasonable proxy for the expected maximum possible peak demand of the grid.

[54] A scale index was included in our Kahn method exercise even though there will probably not be scale escalators in the revenue adjustment indexes of the HECO Companies. This makes sense because the X factor would otherwise be reduced by the historical trend in the operating scale of the sampled utilities. This trend was more rapid historically than that expected for HECO going forward, especially in the early years of our full sample period.

Table 7

Cost-Elasticity Weights for the Scale Index

(derived from Table 6)

Scale Driver	Estimated Cost Elasticity[1]	Commensurate Elasticity Weight[2]
Number of Customers	0.374%	40.9%
Fossil Steam and Other Generation Volume	0.073%	7.9%
Mid-Year Generation Capacity	0.212%	23.2%
Mid-Year Transmission Line Miles	0.086%	9.4%
Peak Demand	0.170%	18.6%
Sum of the Above	0.91%	100%

[1]Defined to be the percent rise in cost due to a 1% increase in the value of the scale variable. For example, PEG's econometric research finds the cost elasticity with respect to customers to be 0.374%, i.e. a 1% increase in number of customers is associated with a 0.374% rise in cost.

[2]The formula is the estimated cost elasticity for the variable divided by the sum of all elasticity estimates.

We calculated the trend in the cost of base rate inputs for each sampled utility. In these calculations, capital cost was defined as the sum of depreciation and amortization expenses and return on average rate base. Rate base was calculated as the difference between gross plant value and accumulated depreciation expenses. We then calculated the value of X that would cause the trends in these costs of our sampled VIEUs to equal the trends in the hypothetical revenue cap indexes on average over the sample period.

The full sample period we considered was the twenty-one year 1997-2017 period. We also considered the results for the last fifteen years (2003-2017) and the last ten years (2008-2017) of the period. Key results of this research are set forth in Table 8 and Figure 3.

Table 8

U.S. VIEU Kahn X Factor Calculations[1,2]

Year	Total Cost [A]	Retail Customers [B]	Mid-Year Average Generation Capacity [C]	Fossil Steam and Other Generation Volume [D]	Mid-Year Average Transmission Line Miles [E]	Ratcheted Maximum Peak Demand [F]	Scale Index[3] [G]	GDPPI Inflation [H]	Kahn X Factors: Using Scale Index [G]+[H]-[A]	Kahn X Factors: Using Customers [B]+[H]-[A]
		Operating Scale								
1997	3.82%	1.80%	0.62%	5.16%	3.43%	3.74%	2.31%	1.71%	0.19%	-0.31%
1998	3.45%	1.92%	0.09%	5.60%	0.32%	3.09%	1.86%	1.08%	-0.51%	-0.45%
1999	1.06%	1.40%	-0.68%	4.25%	0.38%	2.75%	1.30%	1.42%	1.67%	1.77%
2000	6.21%	2.07%	-1.49%	2.99%	-0.68%	2.15%	1.07%	2.25%	-2.89%	-1.90%
2001	3.16%	1.51%	0.55%	1.39%	-1.14%	1.55%	1.03%	2.26%	0.13%	0.61%
2002	2.53%	1.40%	4.69%	-1.61%	0.08%	1.23%	1.77%	1.52%	0.76%	0.39%
2003	2.43%	1.33%	4.58%	-1.09%	0.19%	1.86%	1.88%	1.98%	1.44%	0.89%
2004	2.90%	1.45%	2.03%	-0.11%	-0.07%	0.37%	1.12%	2.71%	0.92%	1.26%
2005	3.79%	1.51%	2.52%	1.44%	-0.31%	2.83%	1.81%	3.17%	1.20%	0.90%
2006	4.06%	0.20%	4.26%	1.07%	-0.93%	1.82%	1.40%	3.02%	0.36%	-0.85%
2007	6.05%	1.40%	3.26%	2.33%	0.10%	1.86%	1.87%	2.63%	-1.55%	-2.02%
2008	4.54%	1.04%	2.59%	2.45%	1.21%	0.70%	1.46%	1.91%	-1.16%	-1.59%
2009	5.10%	0.60%	2.14%	-4.23%	0.98%	0.69%	0.63%	0.78%	-3.69%	-3.71%
2010	7.85%	0.52%	2.21%	-0.06%	1.03%	1.15%	1.03%	1.22%	-5.59%	-6.11%
2011	4.05%	0.44%	1.70%	3.11%	0.72%	1.06%	1.09%	2.04%	-0.92%	-1.56%
2012	2.36%	0.59%	1.39%	-2.13%	1.52%	0.40%	0.61%	1.82%	0.07%	0.05%
2013	4.30%	0.78%	1.13%	1.06%	1.05%	0.31%	0.82%	1.60%	-1.88%	-1.92%
2014	5.41%	0.81%	1.13%	2.33%	0.67%	1.13%	1.05%	1.78%	-2.57%	-2.82%
2015	4.26%	1.02%	1.59%	-1.14%	1.06%	0.73%	0.93%	1.06%	-2.27%	-2.18%
2016	5.29%	1.08%	-0.60%	-2.96%	1.08%	0.21%	0.21%	1.31%	-3.77%	-2.90%
2017	2.67%	0.85%	-0.96%	-1.69%	0.66%	0.16%	0.08%	0.89%	-1.70%	-0.93%
Average Annual Growth Rates										
1997-2017	4.06%	1.13%	1.56%	0.87%	0.54%	1.42%	1.21%	1.82%	**-1.04%**	**-1.11%**
2003-2017	4.34%	0.91%	1.93%	0.03%	0.60%	1.02%	1.07%	1.86%	**-1.41%**	**-1.57%**
2008-2017	4.58%	0.77%	1.23%	-0.33%	1.00%	0.65%	0.79%	1.44%	**-2.35%**	**-2.37%**

Notes:

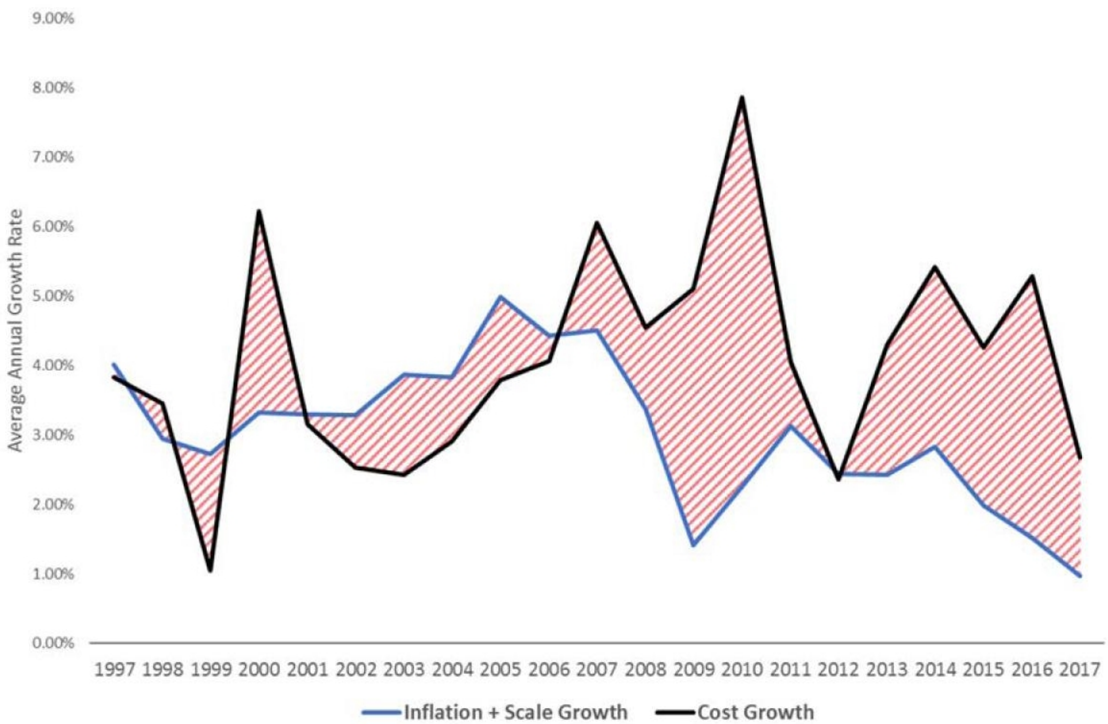
[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include the costs, capacities, and volumes of conventional hydraulic, pumped storage hydraulic, and nuclear generation.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. Elasticity weights were those displayed in Table 7. The formula becomes growth Scale [G] = 40.9% x [B] + 23.2% x [C] + 7.9% x [D] + 9.4% x [E] + 18.6% x [F].

Figure 3

How Cost Growth Outpaced Inflation + Scale Growth



For all sample periods considered, it can be seen that the average annual growth in the cost of sampled VIEUs was considerably more rapid than the average annual growth in the GDPPI. The average annual growth in the scale index was not large enough to close the gap. Thus, the X factor must be negative if the hypothetical revenue adjustment indexes are to track historical VIEU costs on average. Using the scale index, the Kahn X factor was **-1.04%** for the full 1997-2017 sample period. Similar values for X were obtained using the number of customers as the scale escalator in the hypothetical revenue cap indexes.

The Kahn X factors are even more negative for more recent sample periods. Growth in the costs of the sampled VIEUs accelerated while GDPPI inflation and growth in their scale indexes both decelerated. Using the scale index, the indicated X factor fell to **-1.41%** for the last fifteen years (2003-2017) and to **-2.35%** for the last 10 years (2008-2017).

5.7 Explaining Negative X Factors for VIEUs

We have undertaken research to understand the increasingly negative values of the Kahn X factors for VIEUs. Table 8 sheds some light on the problem inasmuch as the difference between the trends in the cost and operating scale of the utilities is their unit cost trends. The unit cost trend averaged 2.85% over the full sample period, and this exceeded the 1.82% average growth of the GDPPI by 103 basis points. Since 1997, unit cost growth has accelerated while GDPPI growth has decelerated.

Digging deeper, relations [9a] and [9b] inform us that when the GDPPI is used as the sole inflation measure in a revenue adjustment index, the X factor should reflect the productivity trend of the industry and the differential between industry input price and GDPPI inflation. For each VIEU in the sample we calculated multifactor indexes of growth in the prices of each utility's base rate inputs. In these calculations, we used a COS capital price index designed to mimic the traditional cost of service treatment of capital cost. We used these indexes to calculate the inflation differential for each company in the sample.

Results of this exercise can be found in Table 9. It can be seen that the growth trend in the industry input price index was substantially more rapid than that of the GDPPI. Over the full 1997-2017 sample period, for example, industry input price growth exceeded GDPPI growth each year by 0.99% on average. Growth in the cost of constructing many kinds of electric utility facilities was especially rapid from 2004 to 2008. The inflation differential was a similar -0.86% for the last fifteen years of the sample period but worsened to -1.38% over the last ten years, due chiefly to a slowdown in GDPPI inflation.

The difference between the Kahn X factor and the inflation differential is a rough estimate of the multifactor productivity trend of VIEUs.[55] Table 9 shows that it was -0.05% over the full sample period and declined to -0.54% over the last fifteen years of the period and to -0.97% over the last ten years.[56]

Table 10 shows the trends in various components of utility cost which contributed to the recent productivity slowdown. It can be seen that growth in the capital cost of VIEUs was much more rapid

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[55] The basis for this statement is that if

$$X^{Kahn} = \overline{MFP} + (\overline{GDPPI} - \overline{Input\ Prices})$$

then

$$\overline{MFP} = X^{Kahn} - (\overline{GDPPI} - \overline{Input\ Prices}).$$

[56] This finding is consistent with the 0.001 estimate of the trend variable parameter in the econometric total cost model.

Table 9

Inflation Differential and Its Impact on X

Year	Kahn X Factor	GDPPI	Industry Input Price Growth	Inflation Differential	Residual X Resulting from Productivity and Other Factors
	[A]	[B]	[C]	[D] = [B] - [C]	[E] = [A] - [D]
1997	0.19%	1.70%	3.72%	-2.01%	2.20%
1998	-0.51%	1.08%	3.98%	-2.90%	2.39%
1999	1.67%	1.42%	0.61%	0.81%	0.85%
2000	-2.89%	2.25%	5.71%	-3.46%	0.57%
2001	0.13%	2.26%	2.04%	0.22%	-0.08%
2002	0.76%	1.52%	1.98%	-0.47%	1.22%
2003	1.44%	1.98%	2.10%	-0.12%	1.55%
2004	0.92%	2.71%	2.33%	0.37%	0.55%
2005	1.20%	3.17%	2.30%	0.87%	0.32%
2006	0.36%	3.02%	2.89%	0.13%	0.23%
2007	-1.55%	2.63%	3.08%	-0.45%	-1.10%
2008	-1.16%	1.91%	4.00%	-2.09%	0.93%
2009	-3.69%	0.78%	2.99%	-2.20%	-1.48%
2010	-5.59%	1.22%	3.01%	-1.79%	-3.81%
2011	-0.92%	2.04%	2.70%	-0.65%	-0.26%
2012	0.07%	1.82%	2.41%	-0.59%	0.67%
2013	-1.88%	1.60%	2.42%	-0.81%	-1.06%
2014	-2.57%	1.78%	2.46%	-0.68%	-1.89%
2015	-2.27%	1.06%	3.41%	-2.35%	0.09%
2016	-3.77%	1.31%	1.21%	0.10%	-3.86%
2017	-1.70%	0.89%	3.58%	-2.69%	0.99%

Average Annual Growth Rates

1997-2017	-1.04%	1.82%	2.81%	**-0.99%**	**-0.05%**
2003-2017	-1.41%	1.86%	2.73%	**-0.86%**	**-0.54%**
2008-2017	-2.35%	1.44%	2.82%	**-1.38%**	**-0.97%**

Table 10

Impact of Component Costs on Kahn X Factor Results[1,2]

Year	GDPPI[3]	Operating Scale		Cost: Capital					Cost: O&M	Cost: Total[8]	Kahn X Factors by Cost Category					
		Retail Customers	Scale Index[4]	Rate of Return[5]	Rate Base[6]	Return on Rate Base	Depreciation and Amortization	Total[7]			Rate Base	Return on Rate Base	Depreciation and Amortization	Capital Cost	O&M Cost	Total Cost
	[A]		[B]	[C]	[D]	[E]=[C]+[D]	[F]	[G]	[H]	[I]	[A]+[B]-[D]	[A]+[B]-[E]	[A]+[B]-[F]	[A]+[B]-[G]	[A]+[B]-[H]	[A]+[B]-[I]
1997	1.71%	1.80%	2.31%	0.20%	2.75%	2.95%	5.21%	3.89%	3.77%	3.82%	1.27%	1.07%	-1.19%	0.13%	0.25%	0.19%
1998	1.08%	1.92%	1.86%	1.46%	1.51%	2.96%	2.21%	2.73%	4.32%	3.45%	1.43%	-0.02%	0.73%	0.21%	-1.38%	-0.51%
1999	1.42%	1.40%	1.30%	-5.68%	1.72%	-3.96%	3.55%	-1.16%	4.56%	1.06%	1.00%	6.68%	-0.82%	3.88%	-1.83%	1.67%
2000	2.25%	2.07%	1.07%	5.04%	2.44%	7.48%	4.51%	6.38%	5.73%	6.21%	0.88%	-4.16%	-1.19%	-3.06%	-2.41%	-2.89%
2001	2.26%	1.51%	1.03%	-2.97%	3.37%	0.40%	4.05%	1.86%	4.99%	3.16%	-0.08%	2.89%	-0.76%	1.43%	-1.70%	0.13%
2002	1.52%	1.40%	1.77%	-2.50%	4.42%	1.92%	3.04%	2.34%	2.66%	2.53%	-1.13%	1.36%	0.25%	0.94%	0.63%	0.76%
2003	1.98%	1.33%	1.88%	-2.59%	4.89%	2.29%	3.43%	2.73%	1.79%	2.43%	-1.02%	1.57%	0.43%	1.13%	2.08%	1.44%
2004	2.71%	1.45%	1.12%	-2.22%	4.71%	2.48%	1.96%	2.17%	3.83%	2.90%	-0.88%	1.34%	1.86%	1.66%	-0.01%	0.92%
2005	3.17%	1.51%	1.81%	-2.41%	4.57%	2.16%	4.68%	3.18%	4.60%	3.79%	0.41%	2.82%	0.30%	1.80%	0.38%	1.20%
2006	3.02%	0.20%	1.40%	-2.23%	4.88%	2.65%	4.08%	3.26%	4.92%	4.06%	-0.45%	1.77%	0.34%	1.16%	-0.49%	0.36%
2007	2.63%	1.40%	1.87%	-1.71%	6.14%	4.43%	6.29%	5.36%	6.63%	6.05%	-1.64%	0.07%	-1.79%	-0.85%	-2.13%	-1.55%
2008	1.91%	1.04%	1.46%	0.58%	8.07%	8.65%	2.41%	5.92%	3.27%	4.54%	-4.70%	-5.28%	0.97%	-2.55%	0.11%	-1.16%
2009	0.78%	0.60%	0.63%	-0.39%	9.65%	9.26%	7.45%	8.59%	0.66%	5.10%	-8.25%	-7.86%	-6.04%	-7.19%	0.75%	-3.69%
2010	1.22%	0.52%	1.03%	-0.35%	10.19%	9.84%	7.46%	8.84%	6.06%	7.85%	-7.94%	-7.58%	-5.20%	-6.59%	-3.81%	-5.59%
2011	2.04%	0.44%	1.09%	-1.48%	8.06%	6.58%	7.79%	7.17%	-0.26%	4.05%	-4.93%	-3.45%	-4.66%	-4.04%	3.39%	-0.92%
2012	1.82%	0.59%	0.61%	-2.22%	7.12%	4.90%	2.18%	3.72%	0.28%	2.36%	-4.69%	-2.47%	0.26%	-1.29%	2.16%	0.07%
2013	1.60%	0.78%	0.82%	-1.03%	6.54%	5.51%	4.58%	5.06%	2.96%	4.30%	-4.12%	-3.09%	-2.15%	-2.63%	-0.53%	-1.88%
2014	1.78%	0.81%	1.05%	-1.89%	6.86%	4.97%	5.13%	5.03%	6.13%	5.41%	-4.03%	-2.14%	-2.30%	-2.19%	-3.30%	-2.57%
2015	1.06%	1.02%	0.93%	1.10%	8.76%	9.86%	6.40%	8.52%	-2.61%	4.26%	-6.77%	-7.87%	-4.41%	-6.53%	4.60%	-2.27%
2016	1.31%	1.08%	0.21%	-3.54%	7.60%	4.06%	11.65%	7.24%	1.70%	5.29%	-6.08%	-2.55%	-10.13%	-5.72%	-0.18%	-3.77%
2017	0.89%	0.85%	0.08%	-0.69%	5.17%	4.48%	4.38%	4.43%	-0.82%	2.67%	-4.19%	-3.51%	-3.40%	-3.45%	1.79%	-1.70%

Average Annual Growth Rates

1997-2017	1.82%	1.13%	1.21%	-1.21%	5.69%	4.47%	4.88%	4.63%	3.10%	4.06%	**-2.66%**	**-1.45%**	**-1.85%**	**-1.61%**	**-0.08%**	**-1.04%**
2003-2017	1.86%	0.91%	1.07%	-1.40%	6.88%	5.48%	5.32%	5.41%	2.61%	4.34%	**-3.95%**	**-2.55%**	**-2.40%**	**-2.49%**	**0.32%**	**-1.41%**
2008-2017	1.44%	0.77%	0.79%	-0.99%	7.80%	6.81%	5.94%	6.45%	1.74%	4.58%	**-5.57%**	**-4.58%**	**-3.71%**	**-4.22%**	**0.50%**	**-2.35%**

Notes:

[1]Costs and volumes that are inapplicable to HECO were excluded from this analysis. These include those for conventional hydraulic, pumped storage hydraulic, and nuclear generation capacity.

[2]All values shown are an average of annual (logarithmic) growth rates of variables on a nationally-representative sample of 45 vertically intergrated electric utilities.

[3]The annual growth rate of the U.S. Gross Domestic Product Price Index ("GDPPI").

[4] Growth in the scale index is a cost-elasticity-weighted average of growth in customers, ratcheted peak demand, transmission line miles, generation capacity, and generation volume. The weights were obtained from econometric cost research for HECO presented in Table 7. The formula becomes *growth* Scale [B] = 40.9% x [*growth* Retail Customers] + 23.2% x [*growth* Generation Capacity] + 7.9% x [*growth* Generation Volume] + 9.4% x [*growth* Transmission Line Miles] + 18.6% x [*growth* Ratcheted Peak Demand].

[5]The annual growth rate of an average of the Edison Electric Institute's "Rate Case Summary" ROE and the embedded cost of debt from FERC Form 1 data of a nationally representative sample of electric utilities.

[6]The growth rate of the average value of rate base at the start and end of the year.

[7]The annual growth rate in total capital cost does not equal the sum of the annual growth rates of return on rate base [E] and depreciation and amortization [F].

[8]The annual growth rate in total cost does not equal the sum of the annual growth rates of capital cost [G] and O&M cost [H].

than growth in their non-fuel O&M expenses. The rate base grew especially rapidly, and its growth has accelerated the most in recent years. Growth in the pro forma *return* on rate base was slowed by a decline in the *rate* of return. Growth in O&M expenses has decelerated in recent years.

Since VIEUs provide distributor services, their productivity growth can be slowed due to the same forces that affect distributor productivity growth. Recall from our discussion in Section 4.6 that these include the following:

- installation of AMI and other smart grid facilities, especially after 2007;[57]
- higher reliability and resiliency standards;
- increased DG penetration; and
- slowing growth in the number of gas customers served by combined gas and electric utilities, especially after 2007.

Sluggish growth in system use and the number of customers served, especially since 2007, has reduced opportunities to increase capacity utilization and incremental scale economies in the distribution sector of VIEUs, and also in their generation and transmission sectors.

There are additional reasons for slowing VIEU productivity growth which are unique to the generation and transmission sectors.

- VIEUs were increasingly encouraged to buy new power supplies rather than build new capacity. This further reduced their opportunities to realize scale economies.
- Some VIEUs made costly investments in equipment to control sulfur and other kinds of pollution from their fossil-fueled power plants. Growth in this capacity was especially brisk after 2007.[58]
- There was an uptick in generation capacity growth from 2001 to 2010 that was due in part to the diminishing ability of many utilities to meet demand growth from existing capacity. Several VIEUs (e.g., CLECO, Kansas City Power & Light, Public Service of Colorado, and

[57] AMI penetration has a statistically significant and positively-signed parameter estimate in our cost model.

[58] Percentage of generation capacity scrubbed has a statistically significant and positively-signed parameter estimate in our cost model.

Southwestern Electric Power) that increased generation capacity chose to build costly power plants fired by solid fossil fuels such as coal and petroleum coke.

- Pollution restrictions, renewable portfolio standards, investment tax incentives, and falling costs of generation from natural gas and renewable resources have spurred additions to gas-fired and renewables-powered generation capacity.[59] Gas-fired generation is cleaner than coal-fired generation and is more capable of offsetting fluctuations in generation from intermittent renewable resources. The benefits to the environment of investments in gas-fired and renewables-powered generation are not included in our productivity calculations.
- As is the case with power distribution, increased reliance on intermittent renewable resources for power supplies has not always translated into generation capacity savings.
- Growth in the generation volumes of many VIEUs (e.g., Indiana Michigan Power, Kansas Gas & Electric, Public Service of Oklahoma, Southern Indiana Gas & Electric, and Southwestern Public Service) has declined, reducing capacity utilization, due to slow native load growth, increased reliance on renewables-powered generation, and low prices in bulk power markets.
- Transmission capex was encouraged by the Energy Policy Act of 2005 and FERC regulatory policy. The North American Electric Reliability Corporation and regional transmission reliability organizations established new reliability standards. Several utilities (e.g., Minnesota Power, Northern States Power, Oklahoma Gas & Electric, and Southwestern Public Service) materially expanded transmission capacity in order to reach remote renewable resources or to improve the functioning of bulk power markets.
- As is true for energy distributors, when new G&T assets are acquired, long-run costs are often reduced by choosing assets with lengthy service lives and an ability to accommodate some future demand growth. However, these assets are to this extent more expensive and slow productivity growth in the short run. Traditional utility capital cost accounting involves historical plant valuations. These valuations magnify the revenue requirement impact of plant additions to the extent that an extensive share of older plant is highly depreciated.

[59] These additions included some conversions of coal-fired capacity to burn gas.

In summary, the slowing productivity growth of VIEUs has reflected an industry faced with slower demand growth but still needing to make sizable capital expenditures in order to install pollution controls, use cleaner-burning natural gas and intermittent renewable resources in generation, improve the functioning of bulk power markets, and modernize the grid. Important benefits of these investments are not captured by our scale indexes.

5.8 Implications for the HECO Companies

Some special considerations are pertinent in an application of our research results to the design of revenue adjustment indexes for HECO Companies. These Companies will have trackers for the cost of major plant additions. However, major plant additions typically account for less than half of the Companies' capex. The GDPPI has been the inflation measure in the current RAM cap and is a prime candidate to play this role in the revenue adjustment indexes. There may be markdowns on the major plant additions that are otherwise eligible for tracker treatment. Moreover, the revenue adjustment indexes will not include scale escalators.

5.9 X Factor Conclusions

Our empirical cost research for the HECO Companies suggests that a revenue adjustment index that uses the GDPPI as the sole inflation measure must typically have a negative X factor if it is to be compensatory for a VIEU. One reason is that the GDPPI tends to understate utility input price inflation. Another is that VIEU productivity growth has slowed.

Appendix

Details of PEG's Empirical Research

This Appendix contains more technical details of PEG's research for HECO. We first discuss our input price indexes. We then address our method for calculating input price inflation and capital cost.

Input Price Indexes

The growth rate of a summary input price index is defined by a formula that involves subindexes measuring growth in the prices of various kinds of inputs. Major decisions in the design of such indexes include their form and the choice of input categories and price subindexes.

The summary input price indexes used in this study were of Törnqvist form. This means that the annual growth rate of each index was determined by the following general formula. Here is the general formula for these indexes:

$$\ln\left(\frac{Input\,Prices_t}{Input\,Prices_{t-1}} \right) = \sum_j \frac{1}{2} \cdot \left(sc_{j,t} + sc_{j,t-1} \right) \cdot \ln\left(\frac{W_{j,t}}{W_{j,t-1}} \right). \qquad [A1]$$

Here, in each year *t*,

$Input\,Prices_t$ = Input price index

$W_{j,t}$ = Price sub-index for input category *j*

$sc_{j,t}$ = Share of input category *j* in applicable total cost.

The growth rate of the index is a weighted average of the growth rates of input price subindexes. Each growth rate is calculated as the logarithm of the ratio of the sub-index values in successive years. The average shares of each input group in the applicable cost of each utility during the two years are the weights.

Capital Cost and Quantity Specification

We explained in Section 3.2 above that there are monetary approaches to the calculation of capital cost that permit its decomposition into a capital quantity index and a capital price index.

$$CK = WK \cdot XK.$$

In our input price and econometric cost research two monetary approaches were chosen to measure the capital cost and input price indexes of each sampled utility.

Geometric Decay

In our econometric cost research a GD capital cost specification was employed. PEG took 1964 as the benchmark year for the capital quantity index. The values for the capital quantity index in this year were based on the net value of plant as reported in the FERC Form 1. We estimated the quantity of plant by dividing this book value by an average of the values of an index of utility construction cost for a period ending in the benchmark year. The construction cost indexes (WKA_t) were the applicable regional Handy-Whitman Index of Cost Trends of Electric Utility Construction for total plant – all steam generation.[60]

The following formula was used to compute values of the capital quantity index in subsequent years:

$$XK_t = (1-d) \cdot XK_{t-1} + \frac{VI_t}{WKA_t}. \qquad \text{[A2]}$$

Here, the parameter d is the economic depreciation rate and VI_t is the value of gross additions to utility plant.

The formula for the corresponding GD capital service price indexes used in the research was

$$WKS_{j,t} = d \cdot WKA_{j,t} + WKA_{j,t-1}\left[r_t - \frac{(WKA_{j,t} - WKA_{j,t-1})}{WKA_{j,t-1}}\right]. \qquad \text{[A3]}$$

The first term in the expression corresponds to the cost of depreciation. The second term corresponds to the real rate of return on capital. Here r is the nominal weight average cost of capital. This term was time-variant but smoothed to reduce capital cost volatility.

COS

A COS capital cost specification was used to calculate the VIEU input price indexes that we used in our inflation differential calculation. Our COS formulas are complex but reflect how capital cost is typically calculated in U.S. utility regulation.

For each utility in each year t of the sample period we define the following terms.

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[60] These data are reported in the Handy-Whitman Index of Public Utility Construction Costs, a publication of Whitman, Requardt and Associates.

CK Total non-tax cost of capital

CKR Return on net plant value

CKD Depreciation expenses

VKA_{t-s} Gross value of plant installed in year t-s

WKA_{t-s} Market cost per unit of plant constructed in year t-s

XKA_{t-s} Quantity of plant added in year $t-s = VK^{add}_{t-s} / WKA_{t-s}$

sck_{t-s} Share of vintage t-s assets in total capital cost

N Average service life of plant

r_t Rate of return on net plant value

WK_{t-s} Price of capital in year t-s

WK Summary capital price index

XK Summary capital quantity index

The non-tax cost of capital is the sum of depreciation and the pro forma return on net plant value. Assuming straight line depreciation and book valuation of utility plant, the non-tax cost of capital can then be expressed as

$$\begin{aligned}
CK_t &= CKD_t + CKR_t \\
&= \textstyle\sum_{s=0}^{N-1} \left(\frac{1}{N}\right) \cdot VKA_{t-s} + r \cdot \sum_{s=0}^{N-1} \left(VKA_{t-s} - s \cdot \frac{1}{N} \cdot VKA_{t-s}\right) \\
&= \textstyle\sum_{s=0}^{N-1} \left(\frac{1}{N}\right) \cdot WKA_{t-s} \cdot XKA_{t-s} + \sum_{s=0}^{N-1} r \cdot \left(1 - s \cdot \frac{1}{N}\right) \cdot WKA_{t-s} \cdot XKA_{t-s} \\
&= \textstyle\sum_{s=0}^{N-1} \left[\frac{1}{N} + r_t \cdot \left(1 - s \cdot \frac{1}{N}\right)\right] \cdot WKA_{t-s} \cdot XKA_{t-s} \\
&= \textstyle\sum_{s=0}^{N-1} WK_{t-s} \cdot XKA_{t-s} \qquad [A4]
\end{aligned}$$

Here the price of assets dating to year t-s is given by

$$WK_{t-s} = \left[\frac{1}{N} + r_t \cdot \left(1 - s \cdot \frac{1}{N}\right)\right] \cdot WKA_{t-s}. \qquad [A5]$$

It can be seen that capital cost is decomposed into the costs attributable to plant dating to numerous past years. The vintage of the annual capital price and quantity is older the higher is the

value of s. Due to depreciation and the historical valuation of plant, WK_{t-s} is lower the higher is the value of s.

From calculus, we know that the growth rate of capital cost (“ΔCK”) is a cost share weighted average of the growth rates of capital costs of various vintages (“ΔCK_{t-s}”). Furthermore,

$$\begin{aligned}\Delta CK &= \sum_{s=0}^{N-1} sck_{t-s} \cdot \Delta CK_{t-s} \\ &= \sum_{s=0}^{N-1} sck_{t-s} \cdot (\Delta WK_{t-s} + \Delta XKA_{t-s}) \\ &= \sum_{s=0}^{N-1} sck_{t-s} \cdot \Delta WK_{t-s} + \sum_{s=0}^{N-1} sck_{t-s} \cdot XKA_{t-s} \\ &= \Delta WK + \Delta XK \qquad \text{[A6]}\end{aligned}$$

Here ΔWK, the growth rate of the capital price, is a cost-share weighted average of the growth rates in the capital service prices for each of the N vintages. It can be seen that market construction costs and the rate of return on net plant value play key roles in capital price index growth.

ΔXK, the growth rate of the capital quantity, is a cost-share weighted average of the growth of the capital quantity indexes for each of the N vintages. Weights will tend to be heavier on the quantities of newer assets since these assets are less depreciated and valued in more recent dollars. In a period of rapid system modernization, there would be higher growth rates in the quantities of vintages that tend to have higher weights and less growth in the quantities of vintages that tend to have lower weights. Capital quantity growth would then accelerate.

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MPIR PROJECT EXAMPLES

Examples of the types of projects and costs that can be recovered through the MPIR mechanism are included in project approval orders, and orders approving recovery of project costs through the MPIR mechanism.

1. Schofield Generating Station Project

The Schofield Generating Station Project (or "SGS Project") is a firm, dispatchable 50 MW power plant, configured with six 8.4 MW, multi-fuel capable reciprocating internal combustion engine generator sets. Under normal operating conditions, the proposed SGS Project would serve all HECO customers. In addition, the SGS Project may be able to continue operations in times of weather related emergencies, because it would be centrally located over eight miles from and approximately 900 feet above the sea. Further, in the event of a significant outage, the SGS Project can start up and provide power without external support, and has the capability to "blackstart" Oahu's grid - that is, the ability to restore power without relying on the grid by providing the power necessary to start other combustion turbine units at the Company's Waiau power plant. Under defined state or national emergency conditions, the SGS Project would be able to provide power directly to the Army facilities of Schofield Barracks, Wheeler Army Airfield, and Field Station Kunia. The Project is self-contained with on-site fuel storage, and is the most "survivable" generating station on Oahu. The SGS runs on a mix of fossil fuel and biofuel.[1]

In August 2012, the Commission (1) granted a waiver from the Framework for Competitive Bidding for the purpose of allowing discussions and negotiations to occur between Hawaiian Electric and the United States Department of the Army ("Army") with regard to construction of a utility owned and operated, firm, renewable, dispatchable, generation security project on federal lands, subject to certain conditions,[2] and (2) approved the commitment of funds in excess of $2,500,000 for the SGS Project, with certain conditions and modifications.[3]

In September 2015, the Commission approved the commitment of funds for the project (with certain conditions), and found that the SGS Project: (a) is consistent with the State's commitment to support the military; (b) supports both State and national security; (c) may permit the retirement of older generating assets sooner rather than later; (d) increases the operational

[1] Re Application for Approval to Commit Funds in Excess of $2,500,000 (Excluding Customer Contributions) for the Purchase and Installation of Item P0001756, Schofield Generating, Docket No. 2014-0113, Decision and Order No. 33178, issued September 29, 2015.
[2] Decision and Order No. 30552 ("D&O 30552"), issued August 1, 2012, in Docket No. 2011-0386. As noted in D&O 30552, the military provides critical services for national security and as a first responder, the project as proposed would appear to support the provision of those services in the event that the utility grid on Oahu has been compromised for some reason, whether through a natural or man-made disaster. D&O 30552 at 10.
[3] Decision and Order No. 33178 ("D&O 33178"), issued September 29, 2015, in Docket No. 2014-0113. In D&O 33178, the Commission found that operational considerations, security and emergency considerations, cost and rate impact considerations, other revenue considerations and renewable energy considerations – on balance - supported approval of the request to commit funds. In addition, D&O 33178 provides for a cost cap. D&O 33178 at 54-56, 84-85.

flexibility and reliability of Hawaiian Electric's system; and (e) may enhance Hawaiian Electric's capability to operate its grid to accommodate increased amounts of renewable energy.[4]

In June 2018,[5] the Commission allowed the Company to accrue costs for the SGS Project for recovery through the Revenue Balancing Account ("RBA") tariff, pursuant to the MPIR adjustment mechanism, beginning the first month following the submission of an attestation, signed by senior management personnel, that the Schofield Generating Station ("SGS") Project is fully functional and available for dispatch, and has satisfied certain Substantial Completion criteria. The Commission found that the SGS Project is an Eligible Project, as contemplated within the MPIR Guidelines.[6]

On June 29, 2018, Hawaiian Electric submitted a signed attestation in compliance with D&O 35556. On August 15, 2018, the Commission issued Order No. 35647, Approving, in Part, Hawaiian Electric Co.'s, Revised Revenue Balancing Account Provision Tariff Sheets, Filed July 18, 2018.Under the MPIR Guidelines, O&M costs, unlike capital costs, are not expressly identified for interim cost recovery under the MPIR adjustment mechanism. Acknowledging this, the Company maintained that allowing recovery of O&M costs under the broader umbrella of "[o]ther relevant costs" under the MPIR Guidelines would be reasonable under the circumstances. In D&O 35556, the Commission agreed, in principle, that O&M expenses may be considered "other relevant costs" under the MPIR Guidelines, but clarified that this determination will be made in prospective MPIR applications on a case by case basis, in accordance with the provisions of the MPIR Guidelines. As it pertains to the SGS Project, the commission found that Hawaiian Electric had not sufficiently satisfied its burden of proof under the MPIR Guidelines. In particular, the Commission noted that, under the MPIR Guidelines, "[a]11 costs that are allowed to be recovered through the MPIR adjustment mechanism[] shall be offset by any related net benefits of implementation of the approved Eligible Project (e.g., cost savings, revenue enhancements offset by O&M expenses, avoided depreciation on retired utility plant, etc.), as those net benefits are quantifiable and can be realized by the electric utility[,]" and should be supported by a business case study included as part of each application.

On September 6, 2018, the Company filed a Business Case Analysis supporting recovery of the estimated net annual O&M amount of $2,087,000, commencing retroactively from the month following the in-service (i.e., effective July 1, 2018). By Order No. 35953, filed December 14, 2018, the Commission approved the Company's request for MPIR recovery of the SGS project's O&M costs, but with accrual commencing as of October 1, 2018 (i.e., the first month after the O&M business case filing).

In Order No. 35953, the Commission approved the Company's Net O&M Request to recover its O&M costs for the SGS Project through the MPIR adjustment mechanism on an interim basis

[4] Re Application for Approval to Commit Funds in Excess of $2,500,000 (Excluding Customer Contributions) for the Purchase and Installation of Item P0001756, Schofield Generating, Docket No. 2014-0113, Decision and Order No. 33178, issued September 29, 2015.
[5] Re Application of Hawaiian Electric Co. for Approval to Recover Costs for Schofield Generating Station through the Major Project Interim Recovery Adjustment Mechanism, Docket No. 2017-0213, Decision and Order No. 35556 ("D&O No. 35556"), filed June 27, 2018, as modified by Order No. 35953, Approving, In Part, Hawaiian Electric Co.'s Request to Recover Net O&M Project Costs and Update Target Revenues filed September 6, 2018, filed December 14, 2018.
[6] D&O 35556 at 37-39.

until the Project's costs are included in the Company's base rates, and allowed the Company to begin accruing the Project's O&M costs as of October 1, 2018, based on the submission date of the Company's Business Case Analysis.

2. Phase 1 Grid Modernization Project

GMS Phase 1 is a foundational project involving interrelated components consisting of capital and deferred expenditures, which include equipment and the associated cost of installing the equipment, computer hardware and related software, software development, software services, and significant interconnection and integration to enable the full benefits of this project and future programs. These components have varying service dates.

On June 21, 2018, the Companies filed their application requesting Commission approval for the commitment for expenditures of approximately $86.3 million related to implementing the first phase ("Phase 1") of the Companies' Grid Modernization Strategy,[7] including the acquisition and deployment of advanced meters, a meter data management system ("MDMS"), a telecommunications network, and related matters. The Companies propose specific accounting and ratemaking treatment for Phase 1, including: (1) deferral of Phase 1's software costs; (2) accrual of allowance for funds used during construction ("AFUDC"), as appropriate, during the applicable construction phases of Phase 1; and (3) recovery of capital costs and deferred costs through the MPIR adjustment mechanism until base rates that reflect the revenue requirements associated with the Capital Costs and Deferred Costs of Phase 1 take effect in a future rate case for each respective Company.

In D&O No. 36230,[8] the Commission approved, subject to the conditions set forth in D&O No. 36230, the requests in the Application. The Commission "generally" found the Companies' proposed accounting treatment for capitalized and deferred expenses to be reasonable. In addition, the Commission found that MPIR recovery for the costs of Phase 1 should be allowed, with certain modifications. The Commission noted that the MPIR Guidelines explicitly list "Grid Modernization Projects" in the list of examples of types of eligible projects. The Commission also noted that the MPIR Guidelines provide for recognition of short-term reductions in utility expenses that result from implementing Major Projects by providing that only costs net of benefits are recoverable through the MPIR mechanism, and required the Companies to develop a methodology for calculating and tracking Phase 1's quantifiable benefits, including identification and quantification of reductions in utility expenses. The Commission approved deferral of the software and other costs for the meter headend and MDMS elements of Phase 1, and the requested recovery of the deferred costs through the MPIR

[7] "Modernizing Hawaii's Grid for our Customers," filed in Docket No. 2017-0226 on August 29, 2017 ("GMS," "Grid Modernization Strategy," or "Strategy"). On February 7, 2018, the Commission directed the Companies to implement the Strategy, subject to the commission's directives and guidance. In re Public Util. Comm'n, Docket No. 2017-0226, Decision and Order No. 35268, filed February 7, 2018 ("Order No. 35268"). A modernized grid is the "backbone" necessary to advance the State's RPS goals, support integration of additional levels of renewables, encourage competition, empower consumers to make their own choices concerning the level and types of electric service they desire, and leverage customer-sited resources to assist in grid operation. In re Hawaiian Electric Co., Docket No. 2016-0087, Order No. 34281, filed January 4, 2017, at 2.

[8] Re Application of Hawaiian Electric Companies for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, and Related Requests, Docket No. 2018-0141, Decision and Order No. 36230 ("D&O No. 36230"), filed March 25, 2019.

mechanism. The Commission implemented fixed cost recovery caps for the MDMS project, the meter headend project, and the telecommunications headend project, and variable cost recovery caps for the advanced meters project and the telecommunications network project that result in a per-meter cap on cost recovery. The Commission also directed the Companies to track all costs and benefits associated with Phase 1. The Commission required the filing of semi-annual progress reports starting on June 30, 2019. The Commission required the Companies to file a Data Access and Privacy Policy and an Advanced Rate Design Strategy within six months of the date of this Order, as a condition of MPIR recovery. D&O No. 36230, as clarified by Order No. 36334, filed May 27, 2019.

The Companies were required to clarify the expected timing and frequency of requests for adjustments to target revenues resulting from the phased implementation of several project elements for each Company ("MPIR Adjustments"), some of which have components entering service each month. The Companies submitted their Proposed MPIR Adjustment Criteria & Details on June 24, 2019.[9] The expected timing and frequency of MPIR adjustments for GMS Phase 1, including a schedule of known, expected, and example possible MPIR Adjustments was included in Exhibit B.

3. West Loch PV Project

On October 3, 2016, Hawaiian Electric filed an application in Docket No. 2016-0342 for approval to commit an estimated $67 million for the West Loch PV Project, which will involve the Company's development and operation of a 20 MW PV farm on property leased from the Navy in the West Loch Annex area of O'ahu. On June 30, 2017, the Commission issued Decision and Order No. 34676 ("D&O 34676"), which approved the project, subject to certain conditions. D&O 34676 (1) approved, subject to certain conditions, Hawaiian Electric's request for a waiver from the Framework for Competitive Bidding for its proposed West Loch Annex Utility-Scale Photovoltaic ("PV") Generating System project, and (2) approved, subject to certain conditions, the Company's request to commit funds in excess of $2,500,000 for the project.[10] In addition, D&O 34676 provides for a Performance Guarantee Mechanism[11] and a Shared Cost Savings Incentive Mechanism,[12] and addresses the benefits of Energy Storage.[13] D&O 34676 caps the project's recoverable capital, in-kind consideration services and O&M costs at $62.4M, $4.7M and $476K, respectively. D&O 34676 also allowed the Company to seek MPIR approval for cost recovery.

On May 29, 2019, the Commission issued Order No. 36335, (1) Affirming Previous Statements regarding MPIR Adjustment Mechanism Recovery, and (2) Requesting Ongoing Updates on the Estimated In-Service Date for the West Loch PV Project. In response to the Commission's letter dated July 18, 2019, Hawaiian Electric submitted an updated estimate of the total project cost for the West Loch PV Project of approximately $58.4 million (including $4.7 million for the in-kind

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[9] Pursuant to Ordering Paragraph 6.A of D&O No. 36230, the Hawaiian Electric Companies submitted (in Exhibit B) the expected timing and frequency of MPIR adjustments for Grid Modernization Strategy ("GMS") Phase 1 elements, including a schedule of known, expected, and example possible MPIR adjustments.
[10] Decision and Order No. 34676 ("D&O 34676"), issued June 30, 2017, in Docket No. 2016-0342.
[11] D&O 34676 at 73-76.
[12] D&O 34676 at 77-78.
[13] D&O 34676 at 79-80.

consideration services). In its 2019 First Quarter Capital Project Status Report, filed May 31, 2019, Hawaiian Electric indicated that the estimated in-service date is September 2019.

4. Maʻalaea M14 HRSG and M16 HRSG Low Load Modification Projects

The projects involved modifying the heat recovery steam generators ("HRSGs") for the M14 and M16 generating units at the Maʻalaea Power Plant to lower the minimum load of the dual train combined cycle #1 ("DTCC1") by an estimated 17 megawatts ("MW"), in order to be able to accept more as-available renewable generation (i.e., DG-PV, Independent Power Producer ("IPP") wind projects, and IPP solar PV projects). The projects were placed in-service on January 27, 2017. The Projects have advanced defined State energy policy directives, including achieving 100% RPS, by reducing renewable energy curtailment and enabling Maui Electric to accept more as-available renewable generation from DG-PV, IPP wind projects, and IPP solar projects.

In D&O 36159,[14] which was not issued until February 11, 2019, the Commission approved Maui Electric's request for deferred accounting treatment and to recover operating and maintenance ("O&M") expenses of $2,460,000 (the "Deferred Costs") for the Maʻalaea M14 heat recovery steam generator ("HRSG") and M16 HRSG Low Load Modification Projects (the "Projects").[15] The Commission allowed Maui Electric to recover the Deferred Costs through a separate regulatory asset account, to be amortized over five years so that the Deferred Costs may be fully amortized before MECO's 2024 test year rate case. The Commission stated that it would further address the recovery of the Deferred Costs in Maui Electric's pending 2018 test year rate case, Docket No. 2017-0150.

In Decision and Order No. 36219 in the Maui Electric 2018 test year rate case (Docket No. 2017-0150), the Commission allowed Maui Electric to include approximately $492,000 in amortized expenses for the Ma'alaea Project in its 2018 Test Year revenue requirement,[16] but directed Maui Electric not to include the unamortized balance in the test year rate base or otherwise accrue any carrying charge on the unamortized balance.

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[14] Re Application of Maui Electric Co. for Approval to Recover Deferred and Capital Costs for the Maʻalaea M14 HRSG and M16 HRSG Low Load Modification Projects through the REIP Surcharge, Docket No. 2016-0345, Decision and Order No. 36159 ("D&O 36159"), filed February 11, 2019.
[15] Maui Electric's Application was filed October 3, 2016, before the issuance of the MPIR guidelines on April 27, 2019.
[16] $2,460,000 / 5 years = 492,000

MAJOR PROJECT INTERIM RECOVERY ADJUSTMENT MECHANISM

In Decision and Order No. 36326 in Phase 1 of this proceeding, the Commission called for the continuation of the Major Project Interim Recovery ("MPIR") adjustment mechanism in its contemplated framework for PBR in Hawai'i. It stated the following:[1]

> The commission will preserve a mechanism for interim cost recovery for exceptional projects, to the extent that it may not be feasible to appropriately provide cost recovery for all such investments during the MRP exclusively through the [annual revenue adjustment ("ARA")]. At this time, the commission envisions that extraordinary relief for eligible projects will continue to be governed according to the MPIR Guidelines;[2] however, the commission may consider revisions to the MPIR Guidelines in Phase 2, in order to remain consistent with the principles, goals, and outcomes of the PBR framework described herein, as well as the specific PBR Mechanisms under consideration.

Decision and Order No. 36326 also stated that consideration of revisions to the MPIR Guidelines presents an opportunity to address capital bias that may be perpetuated through the current MPIR adjustment mechanism and explore how the MPIR may be used to address incentives regarding capital expenditures and operational expenditures.[3]

The Hawaiian Electric Companies agree with the continuation of the MPIR adjustment mechanism. In their Phase 1 statement of position, the Companies stated that the different elements of the multi-year rate plan will have to be balanced to maximize the potential for achieving the various goals and outcomes established in this proceeding, while also enabling the utility to maintain its financial integrity that is essential to meeting its basic obligation to provide safe and reliable electric service to its customers and supporting the achievement of the PBR goals and outcomes.[4] In Decision and Order No. 36326, the Commission stated that it "agrees that preserving the MPIR adjustment mechanism for extraordinary projects is appropriate, to the extent that it may not be feasible to effectively address all such investments during the MRP period exclusively through an externally-indexed revenue formula."[5]

Thus, if the Commission ultimately approves the use of an index-driven revenue formula, depending on the amounts of the parameters of the formula, the MPIR adjustment mechanism may need to be modified to ensure that the multi-year rate plan in total fairly provides the

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[1] Decision and Order No. 36326 at 10.
[2] Footnote 8 of Decision and Order No. 36326 states the following: "The MPIR Guidelines are implemented and provided as Attachment A to Order No. 34514. See In re Public Util. Comm'n, Docket No. 2013-0141, Order No. 34514, 'Establishing Performance Incentive Measures and Addressing Outstanding Schedule B Issues,' filed April 27, 2017 ('Order No. 34514')."
[3] Decision and Order No. 36326 at 34-35.
[4] The Hawaiian Electric Companies explained their positions on the Major Project Interim Recovery ("MPIR") adjustment mechanism at length in their statement of position ("SOP") and reply statement of position ("RSOP") in Phase 1 of this proceeding. See *Statement of Position of the Hawaiian Electric Companies*, filed on March 8, 2019 at 29-31 and Exhibit G; *Reply Statement of Position of the Hawaiian Electric Companies*, filed on April 5, 2019 at 31-44 and Exhibit C.
[5] Decision and Order No. 36326 at 34. Footnote excluded.

Hawaiian Electric Companies with sufficient resources to achieve the outcomes desired by the Commission, given the conditions specific to Hawaiʻi and the Hawaiian Electric Companies. This would be consistent with other jurisdictions that have adopted PBR frameworks. Generally, they have based the revenue adjustments either on a forecast of the utility's revenue requirements or have coupled an index-driven revenue formula with another recovery mechanism like a capital investment tracker or K-factor.

In addition, the Hawaiian Electric Companies propose the following clarifications and modifications for the MPIR adjustment mechanism:

- Clarify that major projects for equipment or facilities for new developments or unserved areas or to serve growth in an area would be eligible for MPIR recovery.
- Modify the MPIR Guidelines to explicitly allow recovery of deferred costs and other expenses of a major project or program.[6] This would address capital bias concerns with the MPIR adjustment mechanism.
- Allow the inclusion of the full investment amount in the MPIR rate base for recovery in the year the project goes into service.

The Companies also agree with the Commission's intention to continue the revenue balancing account ("RBA") and the existing cost trackers and pass-through mechanisms (e.g., Energy Cost Recovery Clause ("ECRC"), Purchased Power Adjustment Clause ("PPAC"), pension and other post-employment benefits tracking mechanisms, Renewable Energy Infrastructure Program ("REIP") surcharge, Demand-Side Management surcharge ("DSM Surcharge")).

<u>The MPIR Mechanism Enables Recovery of Approved Major Project Costs between Rate Cases</u>

The MPIR mechanism resulted from modifications to the Rate Adjustment Mechanism ("RAM") ordered by the Commission in its decoupling reexamination proceeding (Docket No. 2013-0141). In Order No. 32735, the Commission expressed concern about the level of baseline plant additions automatically recovered through the RAM and as a result, established, among other things, a cap on the RAM Revenue Adjustment revenues ("RAM Cap"), based on target revenues[7] approved in the last rate case increased annually by the rate of inflation (i.e., gross domestic product price index or "GDPPI"). The Commission stressed that the RAM Cap and other changes in the order were "designed to provide the commission with control of and prior regulatory review over substantial additions to baseline projects between rate cases"[8] but

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[6] The Consumer Advocate suggested modifications to explicitly clarify that the MPIR adjustment mechanism may be used to recover both capitalized and expenses costs, but may not be used to recover "routine replacements of existing plant assets or expenses that would have been incurred but for the Major Project [.]" See Consumer Advocate's Statement of Position at 32.

[7] Generally, "target revenues" are the annual electric revenues approved by the Commission in the last issued decision and order in the company's most recent test year general rate case, excluding revenue for fuel and purchased power expenses that are recovered either in base rates or in a purchased power adjustment clause; excluding revenue being separately tracked or recovered through any other surcharge or rate tracking mechanism; and excluding amounts for applicable revenue taxes; plus any effective RAM Revenue Adjustment for years subsequent to the most recent completed rate case. See Hawaiian Electric Revenue Balancing Account ("RBA") Provision tariff, Revised Sheet No. 92A, effective January 1, 2018.

[8] Order No. 32735, Docket No. 2013-0141, at 7.

that the Companies may still apply for recovery of "**any type** of Major Project (including related baseline projects considered on a programmatic basis as Major Projects), to be implemented through the RAM, REIP or other proposed mechanism if found to be reasonable and prudent."[9] The Commission further stated that its order "does not deprive the HECO Companies of the opportunity to recover any prudently incurred expenditures or limit orderly recovery for necessary expanded capital programs" but rather that it "limits the amount of unapproved capital project expenditures that can automatically be incorporated into effective rates through the RAM without timely prior regulatory review."[10]

The Commission directed the Companies and the Consumer Advocate to develop standards and guidelines for eligibility of projects and determination of the amount of eligible cost recovery above the RAM Cap or outside of the RAM mechanism through the REIP or other adjustment mechanism. On June 15, 2015, the Companies and the Consumer Advocate filed their *Joint Proposed Modified REIP Framework/Standards and Guidelines* ("Joint Proposed REIP Framework"), which proposed to update and broaden the application of the REIP Framework approved in Docket No. 2007-0416. On the same date, the Companies also filed *Standards and Guidelines for Eligibility of Projects for Cost Recovery through the RAM above the RAM Cap*, which would have enabled the Companies to obtain separate RAM recovery of Major Projects and consolidations of baseline projects that would not be covered by revenues from the RAM Cap.

On April 27, 2017, the Commission issued Order No. 34514, which did not approve either of the June 15, 2015 proposals. Instead, the Commission used and amended constructive language and provisions in the Joint Proposed REIP Framework to establish the MPIR adjustment mechanism and the associated MPIR Guidelines in Attachment A to the order and left the REIP Framework unchanged. The Commission pointed out that, "In making these provisions in [Order No. 32735], the commission did not specify or limit eligibility for recovery to specific types or categories of resources. Nor did the commission prescribe whether any allowed recovery would be through a particular mechanism (e.g., REIP, allowances through the RBA above the RAM Cap, surcharge, deferral of expenses)." As the MPIR Guidelines replaced the provisions of recovery of Major Projects in Order No. 32735, the Commission stated "accordingly, recovery of revenues for costs of Major Projects placed in service between general rate cases will be through the MPIR adjustment mechanism" but also that "the HECO Companies may request interim recovery of revenues for <u>projects that are not Eligible Projects as defined in the Guidelines through other means, including, for qualifying projects, the REIP</u>."[11]

Through Order Nos. 32735 and 34514, the Commission intended to establish a RAM Cap to control the level of expenditures for baseline projects, not subject to a formal review and approval process, that would automatically be recovered through the RAM. At the same time, the Commission intended to provide a means for the Companies to recover between rate cases the costs of Major Projects that it approved through the General Order No. 7 process. These Major Projects included those that are eligible for recovery through the MPIR and the REIP mechanisms. The language in Order No. 34514 cited above also evidently left the door open to

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[9] Order No. 32735, Docket No. 2013-0141, at 89 (emphasis added).
[10] Order No. 32735, Docket No. 2013-0141, at 7.
[11] Order No. 34514, Docket No. 2013-0141, at 105-06 (emphasis added). See also Order No. 34514 at 120-121.

interim recovery of Major Projects that did not meet the eligibility requirements of either the MPIR Guidelines or the REIP Framework, although there was no specification of what the means would be.

Major projects recovered through the MPIR adjustment mechanism must be pre-approved. The current review process has two layers and is very rigorous. First, the Company must obtain Commission approval to commit expenditures for any project in excess of $2.5 million (i.e., a major project), in accordance with General Order No. 7, Rule 2.3.g.2. The Commission and the Consumer Advocate review extensively the need and estimated cost of the project before the Commission acts on the G.O. 7 application.

Second, the Company must also obtain approval in accordance with the MPIR Guidelines to recover the project costs through the MPIR adjustment mechanism. One of the eligibility requirements for MPIR recovery is that the project must be a major project subject to review and approval in accordance with General Order No. 7. The MPIR Guidelines have a separate set of requirements, including the submission of a detailed business case study that should cover all aspects of the planned investments and activities – e.g., reasonably document and quantify the cost/benefit characteristics of the investments and activities and clearly outline how the project will advance transformational efforts with appropriate quantifications.[12] The requirements of General Order No. 7 and the MPIR Guidelines should address the County of Hawai'i's recommendation that "the Commission only allow capex projects that show clear cost-benefit results" for MPIR recovery.[13]

Exhibit B describes examples of projects that the Commission has approved or is in the process of reviewing for recovery through the MPIR adjustment mechanism.

<u>The Scope of the MPIR Adjustment Mechanism Should Be Clarified to Include Projects for New Developments or Unserved Areas or to Serve Growth in an Area</u>

Currently, there is also some uncertainty about the scope of the existing MPIR adjustment mechanism. Clarification on the scope of the eligibility of certain projects for MPIR recovery would allow the Commission and Parties to make a more informed evaluation of the impact of this mechanism on the rate plan and determine the right balance of incentives and recovery mechanisms.

Although Major Projects normally make up a smaller share of the construction budget than baseline projects, Major Projects can have very large capital investments that, if not timely recovered, would have a significant negative impact on the Companies' financials and on their ability to pursue other initiatives during the rate plan period. In addition, from 2018, the proportion of major plant additions increases beginning with the Schofield Generating Station project, which is the first major project to receive approval for MPIR recovery. The annualized

[12] MPIR Guidelines, pages 3-7.

[13] The requirements of General Order No. 7 and the MPIR Guidelines should address the County of Hawai'i's recommendation that "the Commission only allow capex projects that show clear cost-benefit results" [for MPIR recovery]. See *County of Hawai'i's Statement of Position on the Staff Proposal for Updated Performance-Based Regulations*, page 9.

adjustment to target revenues (with revenue taxes) for this project for 2019 is $19,810,800,[14] based on a capital cost of $141,570,000 and annual O&M expenses of $2,087,000.[15] The cost recovery for the capital cost of the West Loch PV project, which is pending a decision on MPIR recovery in Docket No. 2016-0342, is capped at $62.4 million.[16]

The MPIR Guidelines state that the projects and costs that may be eligible for recovery through the MPIR adjustment mechanism are Major Projects subject to review and approval in accordance with the applicable provisions of General Order No. 7, including <u>but not restricted to</u> certain illustrative examples, subject to the Commission's approval in accordance with these guidelines.[17]

The illustrative examples include:

- Infrastructure that is necessary to connect renewable energy projects
- Projects that make it possible to accept more renewable energy
- Projects that encourage clean energy choices and/or customer control to shift or conserve their energy use
- Projects in approved or accepted plans, initiatives, and programs
- Utility scale generation
- Grid modernization projects

The guidelines also state the following:[18]

> With respect to applications seeking approval to utilize the MPIR adjustment mechanism for cost recovery, the electric utility bears the burden of proof that all project costs proposed for MPIR treatment meet the criteria specified herein and are not routine replacements of existing equipment or systems with like kind assets, relocations of existing facilities, restorations of existing facilities, or other kinds of business-as-usual investments.

Order No. 34514 clearly states that the Commission intended the MPIR adjustment mechanism to have a broader scope of eligible projects and specific purposes than the Joint Proposed REIP Framework.[19] Therefore, it leaves to question what kinds of projects would be eligible for MPIR recovery that would not have been eligible under the Joint Proposed REIP Framework. It

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[14] Transmittal 19-01, Attachments 1-2 filed on February 7, 2019, and Schedules B1 and L filed on March 29, 2019.
[15] Transmittal 19-01, filed on March 29, 2019, Schedule L1, page 1.
[16] Hawaiian Electric Company, Inc.'s Reply Statement of Position, filed on November 6, 2017 in Docket No. 2016-0342 at 5.
[17] Order No. 34514, Docket No. 2013-0141, Attachment A at 3-4.
[18] Order No. 34514, Docket No. 2013-0141, Attachment A at 6.
[19] Order No. 34514, Docket No. 2013-0141, at 102.

appears that these projects could be new (as opposed to replacement, relocated or restored) facilities, such as substations, transmission lines and structures, and distribution facilities in new or unserved developments or to serve growth in existing areas. Arguably, these would not be "business-as-usual investments" since they would be serving areas of growth or unserved areas, as opposed to replacing facilities that are already serving customers. Recovery of new service facilities through the MPIR mechanism would be consistent with the concepts articulated in Order Nos. 32735 and 34514 and were not explicitly excluded from eligibility in the MPIR Guidelines. Confirmation of projects that would be eligible for MPIR recovery would be necessary to properly design a multi-year rate plan.

<u>To Address Concerns of Capital Bias, Deferred Costs and Expenses Should Be Eligible for MPIR Recovery</u>

Decision and Order No. 36326 observed the following:[20]

> The Consumer Advocate, Ulupono, Blue Planet, and [the County of Hawai'i] contend that the MPIR Guidelines should be modified to ensure that the MPIR adjustment mechanism does not perpetuate capital bias. The Consumer Advocate recommends considering "clarifying modifications to the MPIR Guidelines ... in order to eliminate the possible appearance that the capital bias may be perpetuated through the MPIR." For example, the Consumer Advocate suggests modifications to explicitly clarify that the MPIR adjustment mechanism may be used to recover both capitalized and expenses costs, but may not be used to recover "routine replacements of existing plant assets or expenses that would have been incurred but for the Major Project [.]"

To address capital bias concerns, the Hawaiian Electric Companies agree with the Consumer Advocate on modifying the MPIR Guidelines to explicitly allow the recovery of both capitalized costs and expenses through the MPIR mechanism, but also to be more precise in stating that deferred expenses would be eligible for recovery through that mechanism.

In Decision and Order No. 36230 in Docket No. 2018-0141, the Commission approved the deferral of software and other costs for the meter headend and meter data management system ("MDMS") elements of Phase 1 of the grid modernization project, and the recovery of the deferred costs through the MPIR adjustment mechanism for Hawai'i Electric Light and Maui Electric.[21] For the deferred expense components of Phase 1, the Commission also approved the accrual of an allowance for funds used during construction ("AFUDC") at each Company's current AFUDC rate until the assets are placed in service,[22] and the accrual of interest on the deferred account balances at the short-term debt rate approved in each Company's most recent

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[20] Decision and Order No. 36326 at B-16. Footnotes excluded. The *Reply Statement of Position of the Hawaiian Electric Companies* filed on April 5, 2019 in Docket No. 2018-0088 responded to the statements on the MPIR mechanism made by Ulupono, Blue Planet and the County of Hawai'i at 34-44.
[21] Decision and Order No. 36230, Docket No. 2018-0141 at 41.
[22] Decision and Order No. 36230, Docket No. 2018-0141 at 31-32, 55, 57.

rate case.[23] In Order No. 36334, the Commission clarified that Hawaiian Electric may recover its deferred Phase 1 costs via the MPIR adjustment mechanism if Hawaiian Electric's meter headend and MDMS components are not in service in its 2020 test year, to the extent such costs are not already recovered through base rates or some other cost recovery mechanism.[24]

In Docket No. 2017-0213, Hawaiian Electric proposed the recovery of capital costs and operation and maintenance ("O&M") expenses for the Schofield Generating Station project through the MPIR adjustment mechanism. In Decision and Order No. 35556, the Commission agreed, in principle, that O&M expenses may be considered "other relevant costs" under the MPIR Guidelines but clarified that "this determination will be made in prospective MPIR applications on a case by case basis, in accordance with the provisions of the MPIR Guidelines."[25] Regarding the Schofield project, the Commission stated that by not providing a business case study, the Company had not complied with the MPIR Guidelines as it pertained to the project O&M expenses and stated that it would not allow inclusion of the O&M costs in the MPIR mechanism unless Hawaiian Electric provided a sufficient business case.[26]

Subsequent to the Company's submission of a business case, the Commission issued Order No. 35953 which found that the Company's business case analysis adequately complied with Decision and Order No. 35556 and approved Hawaiian Electric's request to recover approximately $2,087,000 of net O&M expenses for the Schofield Generating Station project through the MPIR adjustment mechanism on an interim basis until the projects costs are included in Hawaiian Electric's base rates.[27]

In Docket Nos. 2018-0141 and 2017-0213, the Commission approved the recovery of deferred costs for Phase 1 of the grid modernization project and net O&M expenses for the Schofield Generating Station project. These approvals, based on the circumstances of the individual projects, indicate that the recovery of deferred costs and net O&M expenses through the MPIR adjustment mechanism is appropriate. The Companies recommend that MPIR recovery would apply to projects or programs with deferred costs in excess of $2.5 million. The deferred costs would be subject to similar treatment as capital costs under the MPIR Guidelines.

The specific inclusion of deferred costs and net O&M expenses as recoverable through the MPIR adjustment mechanism in the MPIR Guidelines would put capital costs and deferred and net O&M expenses on an equal footing for recovery and would facilitate the removal of any bias of recovery of capital costs over deferred and net O&M expenses in this mechanism. Since the MPIR Guidelines require separate approval for MPIR recovery of each project, the Commission will have the ability to approve or reject recovery of deferred costs or net O&M expenses, given the specifics of the project under review.

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[23] Decision and Order No. 36230, Docket No. 2018-0141 at 32, 56, 57.
[24] Order No. 36334 in Docket No. 2018-0141 at 6-7. On April 26, 2019, Hawaiian Electric filed a notice that it intends to file an application for a general rate increase after June 30, 2019, but no later than September 30, 2019, based on a 2020 calendar test year period.
[25] Decision and Order No. 35556, Docket No. 2017-0213 at 57.
[26] Decision and Order No. 35556, Docket No. 2017-0213 at 62-63.
[27] Order No. 35953, Docket No. 2017-0213 at 7-10.

<u>The Full Investment Amount of a Project Should Be Included in the MPIR Rate Base for Recovery in the Year the Project Goes into Service</u>

In Decision and Order No. 35556 in Docket No. 2017-0213, regarding the recovery of the Schofield Generating Station costs through the MPIR adjustment mechanism, the Commission clarified that "consistent with the average rate base conventions used in determining plant additions to rate base, only half of the Project's costs will be included in the basis for determining return on investment and associated taxes during the calendar year the project goes into service." The Commission also stated the following:[28]

> Regarding HECO's request to utilize an annualized first-year convention, under which the entire Project's costs would have been included in rate base during the first year of service, the commission finds that such an interpretation is not supported by the plain language of the MPIR Guidelines, nor does it comport with the intent and policy considerations underlying the Guidelines. In approving the MPIR Guidelines, the commission did not intend that MPIR should provide an increase in recovery of return in investment on rate base, compared to other existing recovery protocols.

The Companies acknowledge that allowing the MPIR adjustment mechanism to recover the return on the full amount of the investment from the month after completion in the first year would generally result in an increase in recovery compared to other existing recovery protocols as currently configured. The Companies appreciate the Commission's decision to include MPIR revenues in target revenues beginning the month after the project's in-service date.

However, because this proceeding is considering changes to the regulatory framework, including an extension of the period between rate cases, the Companies respectfully request consideration of using the full investment amount to calculate MPIR recovery in the year the project goes into service. Doing so would result in an increase in recovery compared to the rate case and the RAM processes as currently configured but that is because in both cases, the recovery is lagged, and as explained below should at some point be corrected.

Although the Companies may have agreed otherwise to settle a proceeding, they have always maintained that proper ratemaking should match the accrual of revenues with the timing of the incurrence of costs. This means that if a rate period reflects costs beginning on January 1 for a calendar year, the accrual of revenues <u>must</u> also begin on January 1 for the Companies to fully recover their costs. For MPIR recovery, this means that if a project goes into service in a particular month, the recovery of the return on the project investment must also be accrued at the time of the in-service date and must be based on the full investment amount of the project (since the full amount, not one-half, is actually incurred at that time) to reflect the correct carrying cost of the investment. Otherwise, there will be a shortfall in recovery – a shortfall that would be large for a big project and one that the utility would never be able to recover. Without the ability to fully recover their costs, the Companies will not be able to earn their authorized rates of return.

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[28] Decision and Order No. 35556, Docket No. 2017-0213 at 50-51.

For rate cases, §16-601-87 of the Hawai'i Administrative Rules ("HAR") requires the utility to file an application for a general rate increase not more than six months before the beginning of the test period. For the utility to get rate relief at the beginning of the test period, at least interim rate relief would have to be granted in six months. Because of the complexity and the amount of discovery in recent Hawaiian Electric Companies rate cases and the timing of the filing of the Companies' rate case applications, that has not been possible. Hawai'i Revised Statutes ("HRS"), §269-16(d), states that the Commission "shall make every effort to complete its deliberations and issue its decision as expeditiously as possible and before nine months" from the date of the completed rate case application, and that if the Commission has not issued its final decision on a public utility's rate application within the nine-month period, the Commission shall render an interim decision within one month, or within an additional thirty days if evidentiary hearings are incomplete. In accordance with this statute, interim rate relief has generally been granted toward the end of this period, meaning that rate relief has begun well into the test period.

Commissions in other jurisdictions have recognized the need and legitimacy of beginning rate relief at the beginning of the test period.[29] In California, the electric companies such as Southern California Edison Company ("SCE"), Pacific Gas and Electric Company ("PG&E"), Southern California Gas Company ("SoCalGas") and San Diego Gas & Electric Company ("SDG&E") file rate case applications slightly more than a year before the beginning of the test period. This timing is consistent with the California Public Utilities Commission ("CPUC") Rate Case Plan, which calls for a 384-day processing schedule.[30] That is, assuming the CPUC is able to adhere to its goal of processing the rate case in 384 days, the new rates should be in place by the beginning of the test year. Although procedural delays can push the final decision past the beginning of the test year, there is at least a reasonable logic and basis for the expectation that the new rates could be in place by the start of the test year. If the CPUC does not render a final decision by the beginning of the test period, the electric companies are allowed to establish memorandum accounts which provide the utilities with the ability to track the difference in revenue requirement between current rates and final rates eventually approved by the CPUC, in order to have the ability to recover their approved test year revenue requirement for the full year.[31] The CPUC explained that the purpose of its practice of establishing memorandum accounts was to permit general rate case decisions delayed past the start of the test year to be effective as if the decisions had not been delayed.[32]

In Docket No. 2013-0141, the Hawaiian Electric Companies raised the possibility of a change in the Rules of Practice and Procedure in HAR Chapter 61 (now 601) to enable public utilities to file their rate case applications earlier and to allow the establishment of memorandum accounts

[29] See *Hawaiian Electric Companies Initial Statement of Position with Respect to Schedule B Specific Issues*, filed on May 20, 2014 in Docket No. 2013-0141, Exhibit G, Attachment 1.
[30] CPUC Decision 89-01-040 adopted a Rate Case Plan that includes a 384-day processing timeline.
[31] For example, memorandum accounts have been granted for SCE in its 2003, 2006, 2009, 2012 and 2015 test year rate cases; for PG&E in its 2003, 2007 and 2011 test year rate cases; and for SDG&E in its 2004, 2008 and 2012 rate cases. SCE (D.03-05-076, D.06-01-020, D.08-12-049, March 1, 2011 Scoping Memo in A.10-11-015 and March 27, 2014 Scoping Memo in A.13-11-003); PG&E (D.02-12-073, D.06-10-033 and D.10-11-018); and SDG&E/SoCalGas (D.03-12-057, D.07-12-053 and March 2, 2011 Scoping Memo in A.10-12-005/A.10-12-006).
[32] Decision on Motions for Memorandum Accounts, A.07-11-011, D.08-12-049 (Cal. P.U.C., December 19, 2008).

to accrue revenues from the beginning of the test year in rate cases.[33] In Order No. 34514, the Commission noted that, to the extent that cooperation, standardization, minimum filing requirements, or other measures identified in that proceeding may result in more efficient and effective review or settlement of issues, this may reduce the amount of time to process general rate case applications, with possible associated reductions in institutional regulatory lag. For those reasons, the Commission found that it was not necessary or reasonable to implement specific measures to reduce regulatory lag through changes in filing timing requirements, utilization of memorandum accounts or other measures proposed to streamline the rate case process and would not initiate rulemaking proceedings to make changes regarding the filing or timing of general rate case procedures at that time.[34]

There have been similar issues with the Companies' rate adjustment mechanism ("RAM"). A dispute arose in Transmittal No. 11-02 between the Companies and the Consumer Advocate on what the agreement between the parties was on when the accrual of RAM revenues would begin. The Companies asserted that the accrual of revenues should begin January 1 of the RAM period while the Consumer Advocate stated that the accrual should begin on the effective date of the RBA rate adjustment tariff (usually June 1). In the *Order regarding Attachment 5 and Directing HECO to File Tariff Amendments* issued on May 20, 2011, the Commission agreed with the Consumer Advocate's approach, stating that "its approach reduces, but does not entirely eliminate regulatory lag, and is administratively simpler to implement."

However, in Decision and Order No. 36326 in Phase 1 of this proceeding, the Commission stated the following:[35]

> Likewise, consistent with the Principle of ensuring utility financial integrity, in addition to other considerations in the design and examination of the ARA, the commission will consider measures to reduce lag in implementing the accrual and/or collection of approved revenues. Regulatory lag has consistently been raised by the Companies as a concern for certain mechanisms (e.g., the RBA's approximately five-month lag between January and the June effective date). Establishing target revenues with an automatic annual adjustment formula will mitigate this concern.

The accrual of revenues at the beginning of a rate case test period or the RAM period would be equivalent to including the full investment in rate base for the first year of MPIR recovery in that both would generally enable the utility to fully recover its costs. As has been the convention in this jurisdiction, calculation of the revenue requirement for rate cases and the RAM utilize an average rate base (i.e., the simple average of the beginning and end balances of rate base in the test period). Because plant additions go into service over the course of the test period, utilizing an average rate base will enable the utility on average to fully recover its costs if it is able to accrue revenues equal to the revenue requirement over twelve months of the test period beginning January 1.

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[33] See *Hawaiian Electric Companies Initial Statement of Position with Respect to Schedule B Specific Issues*, filed on May 20, 2014 in Docket No. 2013-0141, Exhibit G at 22-28.
[34] Order No. 34514, Docket No. 2013-0141 at 76-77.
[35] Decision and Order No. 36326 at 31-32.

For MPIR recovery, the utility is able to accrue revenues beginning the month after the project's in-service date. If it is able to recover the return on only half of the investment in the initial year, there will be a shortfall of recovery. The only way for MPIR projects on average to obtain full recovery using an average rate base in the initial year is to allow the accrual of MPIR revenues for the full twelve months of the initial year, regardless of the in-service date of the project in that year. The same result, on average, can be obtained by including the full investment in the calculation of the revenue requirement if the onset of recovery is at the in-service date of the project. This need is especially acute for large projects like the Schofield Generating Station which required an investment of over $140 million. The shortfall in recovery due to use of an average rate base was approximately $3.4 million for the months of July through December 2018.[36] This constitutes a loss in recovery, not a lag. Hawaiian Electric will not be able to recover in rates the return on the other half of the investment lost in the first year.

The Commission has recognized the need to include the full costs associated with major generating unit and major transmission line additions in a number of rate cases. For example, in Docket No. 7000, which utilized a 1993 test year as well as a 1992 test year for Maui Electric, the Commission authorized two step increases in 1993 (timed to coincide with the addition of the units to Maui Electric's system) based on the annual costs and benefits of adding the M16 and M15 generating units to Maui Electric's system. The annual costs included depreciation expenses.[37] In Docket No. 7766, which utilized a 1995 test year, the Commission authorized, on an interim basis, a step increase in August 1995 based on the annual costs of adding the Waiau-CIP transmission lines to Hawaiian Electric's system.

The Commission also approved the use of step increases for purchase power agreement ("PPA") capacity costs, based on the full annual costs of such PPAs, in prior cases. In Docket No. 6531, which utilized a 1990 test year, the Commission authorized the inclusion of the annual costs and benefits associated with the Kalaeloa Partners, L.P. ("Kalaeloa") PPA (by which Hawaiian Electric added 180 megawatts ("MW") to its system) in revenue requirements, and a step increase based on the annual costs and benefits, even though the Kalaeloa facility went into commercial operation five months after the conclusion of the 1990 test year.

In Docket No. 6998, which utilized a 1992 test year, the Commission authorized a step increase in September 1992 for Hawaiian Electric's PPA with AES Barbers Point, Inc. (later known as AES Hawaii, Inc.), by which Hawaiian Electric added another 180 MW to its system. The 1992 test year revenue requirements in Docket No. 6998 included the annual costs and benefits for the AES-BP PPA, even though AES-BP went into commercial operation in September 1992.

In the case of firm capacity PPAs for non-fossil fuel producers, the Firm Capacity Surcharge allows for step increases, based on annual firm capacity costs, outside of a rate case. For

[36] *Updated Responses to the Commission's Information Requests*, filed on July 18, 2018, Docket No. 2017-0213, Schedules B1 and L. The loss in recovery for the months of July through December 2018 was $3.4 million based on the monthly factors for July through December 2018 (i.e., 51.67%) on Schedule B1 (i.e. $6.6 million X 51.67% = $3.4 million).

[37] The impact of the adjustment to include the full costs of these generating units on revenue requirements was offset to some extent in the final decision and order by recognizing annual sales and revenues (net of fuel expense) for new customers added in 1993.

example, Puna Geothermal Venture ("PGV") went into commercial service in June 1993, adding $4.4 million in capacity payments and revenue taxes to Hawai'i Electric Light's expenses on an annual basis. Hawai'i Electric Light was able to recover the full costs of adding this capacity to its system as of the PGV in service date by means of Hawai'i Electric Light's Firm Capacity Surcharge. Maui Electric also was allowed to recover the additional capacity payment costs that it incurred pursuant to its Amended and Restated PPA with HC&S beginning in December 1990.

"Proper" ratemaking requires that the end results be reasonable, and that the utility be provided with a realistic opportunity to earn a fair return on its investment in plant actually used or useful. As explained above, this would not happen if the Companies are only able to recover the return of half of the investment from the in-service date in the initial year of service. In the past, the Commission has approved the inclusion of the full investment in step increases in rate cases and for PPA firm capacity costs. Hence, the Hawaiian Electric Companies respectfully request that the Commission grant equivalent treatment for MPIR recovery of major projects.

<u>The MPIR Adjustment Mechanism Will Need to Align with the Design of the Multi-Year Rate Plan</u>

As explained in Decision and Order No. 36326, Phase 2 will focus on the development of a five-year rate plan with an indexed annual revenue adjustment ("ARA") according to the formula:[38]

Annual Revenue Adjustment = (Inflation Factor) - (X-Factor) + (Z-Factor) - Consumer Dividend

Decision and Order No. 36326 also states that the MPIR adjustment mechanism will continue to provide revenues for extraordinary projects as approved by the commission, above revenues established by the ARA.[39] The Commission stated that it "agrees that preserving the MPIR adjustment mechanism for extraordinary projects is appropriate, to the extent that it may not be feasible to effectively address all such investments during the MRP period exclusively through an externally-indexed revenue formula."[40] The contemplated rate plan would also include the already-existing revenue balancing account ("RBA"), certain existing tracking mechanisms (e.g., Energy Cost Recovery Clause ("ECRC"), Purchased Power Adjustment Clause ("PPAC"), pension and other post-employment benefits tracking mechanisms, Renewable Energy Infrastructure Program ("REIP") surcharge, Demand-Side Management surcharge ("DSM Surcharge")), a symmetric earnings sharing mechanism, and additional performance incentive mechanisms ("PIMs") to drive achievement of certain priority outcomes.[41]

The different elements of the multi-year rate plan will have to be balanced to maximize the potential for achieving the various goals and outcomes established in this proceeding, while also enabling the utility to maintain its financial integrity that is essential to meeting its basic obligation to provide safe and reliable electric service to its customers and supporting the achievement of the PBR goals and outcomes. The appropriate level of escalation of revenues in

[38] Decision and Order No. 36326 at 8.
[39] Decision and Order No. 36326 at 33.
[40] Decision and Order No. 36326 at 34. Footnote excluded.
[41] Decision and Order No. 36326 at 11-13.

the ARA will depend on what elements will be included in the rate plan and what the specific parameters of the different elements of the rate plan will be. If an external index is used to determine the X-Factor, the MPIR adjustment mechanism may need to be broadened or additional recovery mechanisms may need to be established to generate a sufficient level of revenues.

The extension of the period of the rate plan from three to five years and the imposition of a customer dividend and any other provision that minimizes or reduces the level of revenues will stress the ability of the Companies to maintain their financial integrity during the rate period. In addition, the use of an index-driven revenue formula based on the cost characteristics of a broad range of electric utilities may not reflect conditions specific to Hawai‘i that have a significant impact on cost (e.g., accelerated integration of renewables, grid modernization, high cost of goods and services, isolated island grids, lack of scale).

As the Consumer Advocate has stated, the RAM approved in Docket No. 2013-0274 was conservatively designed.[42] Using a five-year average for baseline plant additions, allowing the O&M RAM to increase by the level of inflation without allowing for the inclusion of expenses for new programs or initiatives, no increases for management labor and an asymmetric earnings sharing mechanism with sharing only on the upside of the approved return on equity were some of the conservative elements in the original RAM that constrained the amount of approved revenues. The establishment of the RAM Cap made RAM revenues even more conservative, not allowing target revenues to grow more than the GDPPI each year. The RAM Cap implemented in 2015, and the reversion to a June 1st accrual in 2017 of the RAM increase for Hawaiian Electric, have made it difficult for the Companies to earn their authorized returns (even with the general rate case increases). Since that the establishment of the RAM Cap in 2015, none of the Hawaiian Electric Companies have earned their authorized rates of return.[43] If a positive X-factor, a zero Z-factor and a customer dividend are included in the ARA formula, the resulting revenues would be even less than the revenues generated through the current RAM Cap design.

The Companies' reply statement of position in Phase 1 included an analysis submitted by The Brattle Group that showed that Hawaiian Electric target revenues increased over the 2012–2016 period on average by 3.43%. In order for Hawaiian Electric to have achieved the authorized ROE in each year, the required increase would have been 4.35%.[44]

Some parties may argue that an index-driven revenue formula would disconnect revenues from the cost of service but comparisons between the projected performance of the annual revenue adjustment and the Companies' authorized rates of return would constitute a reversion to cost of service ratemaking. However, State law (Hawai‘i Revised Statutes § 269-16(b)(3)) still requires that the public utilities have the opportunity to earn a fair return on their property used for public utility purposes. The consideration of utility specific costs and the impact on utility financial requirements in the design of multi-year rate plans is common in other jurisdictions.

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[42] See, for example, Panel Hearing Transcript, Volume I, June 29, 2009, at 92-94, 97; Volume II, June 30, 2009, at 306, 342-343.

[43] See "Ratemaking ROE vs Authorized graphs in the *Statement of Position of the Hawaiian Electric Companies* filed on March 8, 2019 in Docket No. 2018-0088, Exhibit E at 13-14.

[44] *Replay Statement of Position of the Hawaiian Electric Companies*, filed on April 5, 2019, Exhibit B at 2.

More revenue adjustment mechanisms are based on company forecasts. Those that are index-driven typically include K-factors or capital trackers to supplement revenues so that the company can better recover its costs. As Dr. Brown explains in Exhibit D, six of seven states in the United States with multi-year rate plans, including New York and California, have utility-specific annual revenue adjustments based on company forecasts. Eversource in Massachusetts uses an external benchmark and a capital tracker for grid modernization expenditures. All electric distribution and transmission utilities in Australia and Great Britain have multi-year rate plans. There are fourteen electric distribution utilities in Australia and fourteen in Great Britain. All of them have annual revenue adjustments that are utility-specific. In Canada there are multi-year rate plans in place in British Columbia, Alberta and Ontario that use external benchmarks usually for O&M but have utility-specific mechanisms for capital.[45]

Thus, testing the effect of PBR mechanisms, even if they are index-driven, on the Companies' rates of return should be done as a check on the sufficiency of the rate plan.

Some parties have proposed more restrictions or requirements on the use of the MPIR adjustment mechanism. If the application of the MPIR is scaled back, the escalation of revenues from the ARA would need to be higher to allow for the recovery of projects no longer eligible for MPIR recovery and to enable the Companies to maintain their financial integrity. At the same time, the ARA would act as a revenue cap and still provide an incentive for the Companies to control their costs. The key will be to balance incentives to enable the Companies to achieve desired outcomes without the incentives, requirements or restrictions becoming punitive. If the desire is to provide incentives for the Companies to do more to support transformational goals and outcomes, and at a faster pace, and at the same time have longer periods between rate cases, those incentives should include opportunities for the Companies to recover the associated costs; not make recovery more difficult by imposing more restrictions and requirements on the recovery mechanisms. Constraining the ability to recover prudently incurred costs will have the opposite effect, making it more difficult to initiate, implement and finance desired programs and slowing progress towards modernizing the grid and achieving the transformational goals and outcomes desired by parties in this proceeding.

To achieve renewable energy and transformation goals, the Companies have to expend dollars. In the *Statement of Position of the Hawaiian Electric Companies* filed on March 8, 2019 in this proceeding, the Companies explained how constraining the ability of the RAM (or in this case the ARA) to recover costs, as a way to reduce rates, can actually inhibit progress towards increasing the use of low-cost renewable energy and ultimately reducing rates. Specifically, it stated that because fuel and purchased power costs are the two largest cost drivers of customer rates, the key to reducing rates is to substitute low cost renewable energy for fossil fuel generation. Grid modernization is essential to adding more renewable energy but may require more, not less O&M and capital expenditures. Thus, over-constraining cost recovery of O&M and capital expenditures, as a way of reducing rates, can result in disincentives to incur the very

[45] Fortis BC is an exception as it indexes historical O&M expenses and historical capital expenses rather than revenues. The indexed O&M and capex are applied to opening rate base to calculate revenue requirements in each year of the plan. It also includes flow-through treatment for larger capital projects (projects over $20m).

costs that will enable the reduction in the fuel and purchased power expenses that would benefit customers.[46]

[46] See *Statement of Position of the Hawaiian Electric Companies* filed on March 8, 2019 at 21-24.

Modifying the PBR framework in Hawai‘i

PRECEDENTS FOR DETERMINING AN ANNUAL REVENUE ADJUSTMENT IN MULTI-YEAR RATE PLANS

PREPARED FOR

The Hawaiian Electric Companies

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THE Brattle GROUP

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I. Introduction

A. Brattle's assignment

The Public Utilities Commission of the State of Hawai'i has instituted a proceeding to investigate performance based ratemaking (PBR).[1] The Commission subsequently issued Decision and Order No. 36326 as a guide to Phase 2 of the proceeding. The Commission's Decision and Order determines that Phase 2 will include developing the detailed design for a five-year rate plan (multi-year rate plan) with an "index driven annual revenue adjustment".[2] The annual revenue adjustment is to be of the form inflation factor minus X-factor, plus other adjustments.[3]

The Hawaiian Electric Companies ("the Companies") have asked The Brattle Group to comment on how the annual revenue adjustment described by the Commission compares with annual revenue adjustments in multi-year rate plans implemented for electric utilities in other jurisdictions.

This report addresses the derivation of the annual revenue adjustment but does not address other plan features.

B. Structure of this report

This report is structured as follows:

- In Section 2 I discuss methods for determining the annual revenue adjustment in multi-year rate plans; and
- In Section 3 I summarize precedents from jurisdictions in the US, Canada, Australia and Great Britain.

1 Order No. 35411 in PUC of Hawai'i Docket 2018-088, filed April 18, 2018.

2 Decision and Order No. 36326, Docket 2018-088, filed May 23, 2019, p. 8.

3 *Ibid.*, p. 29. The other adjustments are a Z-factor and a "customer dividend".

II. Determining the annual revenue adjustment

A. Inflation and a fixed revenue adjustment

Some multi-year rate plans have an annual revenue adjustments linked to inflation, while others do not.[4] In addition, whether or not there is inflation indexation, multi-year rate plans also include a fixed annual revenue adjustment term. Thus some plans have an annual revenue adjustment of (inflation plus or minus a fixed amount), while others simply have the fixed amount. The inflation term is updated each year to reflect the latest inflation results, but the fixed amounts are determined at the outset of the plan and are not updated. The focus of this paper is on how these annual adjustments have been determined in the various jurisdictions that have implemented multi-year rate plans.

In the proceedings I have reviewed, the annual revenue adjustment has been determined in one of two ways. The first way I label "utility-specific" because the amount of the annual revenue adjustment is determined principally or solely by examining information about the utility's anticipated future costs. This could include reviewing the historical trend in that utility's costs, and or a forecast of costs over the plan term. The second way I label "external benchmark" because the amount of the annual revenue adjustment is determined solely by examining information about other utilities, rather than the utility to which the plan will be applied.

If the annual revenue adjustment is utility-specific, then naturally two different utilities subject to otherwise similar plans would have different annual revenue adjustments. In contrast, if the annual revenue adjustment comes from an external benchmark, then the two utilities would receive the same annual revenue adjustments if their plans were determined at the same time. The external benchmark would typically come from analyzing historical accounting and other data for a large group of utilities.

In this note I show that current and recent multi-year rate plans usually have utility-specific annual revenue adjustments.

Particularly if the annual revenue adjustment is based on an external benchmark, then the plan is likely to require mechanisms to recover additional revenues over and above the annual adjustment based on the external benchmark. I discuss some such mechanisms in section II.B, and I give some quantified examples in section III.D.

[4] For example, the multi-year rate plan for Eversource in Massachusetts includes an inflation adjustment, while the multi-year rate plans for the California utilities do not.

B. Y-, Z- and K- factors

A PBR plan in which the base revenues have an annual adjustment based on an external benchmark (ie, a generic rather than utility-specific X factor),[5] will typically have other mechanisms for collecting additional revenues, reflecting various items that are not "captured" within the I – X revenue adjustment. Terms used to describe these additional revenues include Y-factor, Z-factor and K-factor.

Y-, Z- and K- factors provide revenue to cover the cost of items that are not covered by base revenues (as escalated by I- X).

Y- and Z- factors cover items that are added to the utility's costs for reasons that are nothing to do with the utility management ("outside management control"). The distinction between Y- and Z- is that Y- covers a defined list of items that, when the plan is designed, are already anticipated to need Y-factor treatment. The items are known, but the costs that will be incurred are not. Z- is more of a catch-all that permits the utility to bring forward applications, during the plan term, for cost recovery for "new" items that were not anticipated when the plan was designed and the list of items covered by Y- was developed. For example: "With respect to flow-through rate adjustments, the Commission considers that flow-through rate adjustments arise from cost elements that are not unforeseen one time events. Flow-through items arise in the normal course of business, but are such that the company has no control over them."[6]

The K-factor covers other expenditures that are not recovered by the I – X revenue adjustment. Usually, but not always, the K-factor covers capital expenditures rather than opex, and usually, but not always, the K-factor is for specific projects or programs.[7]

The Alberta PBR plans provide a recent example of a Commission determination which sets out some criteria for what items should qualify under each of Y-, Z- and K- and also provides some specific examples.

1. Y-factor

The Y-factor is effectively like a flow-through or deferral account (similar to the ECAC/ECRC in Hawai'i). In the Alberta proceeding the following criteria were adopted:[8]

1. The costs must be attributable to events outside management's control.

[5] These additional factors tend to be not needed or less significant (ie, recover a smaller proportion of revenues relative to base rates) in jurisdictions where the annual adjustment to base revenues is utility-specific.

[6] Alberta Utilities Commission, Decision 2009-035, paragraph 251.

[7] For example, the grid modernization tracker of Eversource, described below, can recover both opex and capital costs. While the Eversource tracker covers only projects associated with grid modernization, the K-factor in Alberta can cover a wide variety of projects.

[8] Alberta Utilities Commission, Decision 2012-237, paragraph 631.

2. The costs must be material. They must have a significant influence on the operation of the company otherwise the costs should be expensed or recognized as income, in the normal course of business.
3. The costs should not have a significant influence on the inflation factor in the PBR formulas.
4. The costs must be prudently incurred.
5. All costs must be of a recurring nature, and there must be the potential for a high level of variability in the annual financial impacts.

Examples of items included within Y- are franchise fees and local taxes. The Alberta Utilities Commission rejected Y-factor treatment for executive bonuses, vegetation management and smart meters.

2. Z-factor

In the Alberta proceeding, the criteria for Z- are similar to those for Y-. However, Z- is "one off" rather than recurring.

An example of an item qualifying for Z-factor treatment is costs associated with a wild-fire which destroyed utility assets.[9]

3. K-factor

If the X-factor is not utility-specific and therefore does not recognize the particular circumstances of the individual utility, the annual revenue adjustment of I – X may not provide sufficient revenue to support needed capital investment. (In principle, the same could be true of operating expenditures, but typically concerns are usually focused on supporting capex.) As a result, the plan may need an additional source of revenue to support capex. This mechanism could be termed a "tracker" or is sometimes called a K-factor. Sometimes the K-factor has a true-up and sometimes not.[10] For example: "The Commission recognizes that the TFP study used to determine the X factor adopted by the Commission in this proceeding measures the rate of productivity change of the distribution industry over time necessarily reflecting input costs including the types of capital expenditures and all of the types of year to year fluctuations in the need for capital referred to by the companies. Nevertheless, the Commission acknowledges that there are circumstances in which a PBR plan would need to provide for revenues in addition to the revenues generated by the I-X mechanism in order to provide for

9 Alberta Utilities Commission, Decision 21608-D01-2018 (Z Factor Application for Recovery of 2016 Regional Municipality of Wood Buffalo Wildfire Costs).

10 If the K-factor is trued up, then the difference between the revenue requirement impact of the actual capital expenditures, and the K-factor revenue already collected, is charged or refunded to customers. The K-factor in the first term of the Alberta PBR plans was trued up, while in the second term for the most part it is not. See footnote 15 below.

some necessary capital expenditures. The way in which this is accomplished is through a capital factor (K factor) in the PBR plan."[11]

In the Alberta proceeding for the 2013-17 plans, the Commission ultimately determined the following three criteria, all of which had to be met for expenditure to qualify for K-factor recovery:[12]

1. The project must be outside of the normal course of the company's ongoing operations.
2. Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party.[13]
3. The project must have a material effect on the company's finances.

However, it proved controversial to determine how to apply the first criterion ("outside of the normal course"). Ultimately, in the 2013–17 plans the Commission applied a test which allowed the utilities to include any type of capital project if it could be shown that the rate of capital additions exceeded the rate of depreciation by more than I – X, for the same type of project or program in existing rate base.[14] For the second generation PBR plans (2018 to 2022), the Commission changed the design of the K-factor. The new K-factor (called "K-bar") is an annual revenue adjustment which is fixed at the outset of the plan and is not trued up.[15]

[11] Alberta Utilities Commission, Decision 2012-237, paragraph 549.

[12] Alberta Utilities Commission, Decision 2012-237, paragraph 592.

[13] The Alberta PBR plans for electric utilities are price caps rather than revenue caps. Thus installing new assets, such as assets associated with a new residential or industrial development, increases billing determinants and hence revenues.

[14] Decision 2013-435, December 6, 2013, paragraph 1,098: "The Commission determined that a project would satisfy Criterion 1 if it passes the accounting test based on the use of the net cost project approach ["the revenue generated under the I-X mechanism for each capital project (or capital program or project category) was compared to the forecast revenue requirement associated with that capital project (or capital program or project category) in 2013."(paragraph 174)] and it satisfies the requirements of the project assessment ["The purpose of the project assessment is to demonstrate that a project proposed for capital tracker treatment is (i) required to provide utility service at adequate levels and, if so, (ii) the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable."(paragraph 278)]."

[15] The calculation of the K-bar annual revenue adjustment depends on the difference between the revenue associated with K-bar capital in base rates and the revenue requirement associated with K-bar capital, calculated on the basis of the historical rate of K-bar additions. See Decision 20414-D01-2016 (Errata), Alberta Utilities Commission, paragraph 254. The flow-through / true-up part of the K-factor is now limited to projects which are "extraordinary and not previously included in the distribution utility's rate base" and must be "required by a third party" (*Ibid.*, paragraph 198). For example, FortisAlberta had no projects qualifying for flow-through / true-up in 2019 (see Decision 23893-D01-2018 (Errata), paragraph 34). In contrast, FortisAlberta incorporated $76m of K-factor revenue in 2017 rates, representing about 15% of base revenue (FortisAlberta 2017 PBR Filing, Schedule 4.1-D1, September 9. 2016).

4. Customer dividend

A customer dividend or "stretch" factor is sometimes added to the X factor in a PBR plan (ie, it makes the X-factor larger, therefore reduces annual revenue adjustments). It is important to note that the size of the customer dividend has no influence on the strength of PBR incentives (just as the magnitude of X has no impact on incentives. For example: "The Commission agrees with the experts of the companies, NERA and the CCA, that while the size of the X factor affects a company's earnings, it has no influence on the incentives for the company to reduce costs. As the companies' and the CCA's experts pointed out, the PBR plans derive their incentives from the decoupling of a company's revenues from its costs as well as from the length of time of the PBR term, and not from the magnitude of the X factor itself."[16] Also "Among other arguments, the interveners submitted that a stretch factor is necessary as it strengthens the incentives under PBR.[f/n omitted] On this point, the Commission disagrees. As indicated in Decision 2012-237, while the size of a stretch factor affects a utility's earnings, it has no influence on the incentives for the utility to reduce costs. PBR plans derive their incentives from the decoupling of a utility's revenues from its costs as well as from the length of time between rate cases and not from the magnitude of the X factor (to which the stretch factor contributes)."[17]

The ostensible function of the customer dividend is to anticipate that the utility will be able to keep its costs within the I – X revenue cap, such that it is expected to generate additional profits if revenues grow at I – X (ie, it is expected to exceed the authorized ROE if revenues grow at I - X). In theory, the logic for expecting the utility to "beat" the I – X cap is that if the I – X trend is estimated from a set of utilities that face relatively weaker incentives to control costs (for example, because their rate cases are more frequent than every five years), the additional financial incentive facing the utility with a five-year PBR term will cause it to improve faster. The customer dividend takes this anticipated out-performance, and gives it to customers by reducing the annual revenue adjustment. Thus the customer dividend represents the anticipated improved performance of the utility relative to the assumed trend represented by the X factor.

If the annual revenue adjustment is already utility-specific (rather than based on an external benchmark), it can already incorporate the anticipated future performance of the utility in controlling costs, and therefore the logic for a customer dividend disappears.

In practice, a customer dividend is sometimes added to an annual revenue adjustment based on an external benchmark. It appears that Commissions commonly choose a number around 0.2%. This number is often based on judgment rather than any analysis. For example: "As parties pointed out, the determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a 'definitive analytical source' like the TFP study represents."[18]

16 Alberta Utilities Commission, Decision 2012-237, paragraph 257.

17 Alberta Utilities Commission, Decision 20414-D01-2016 (Errata), paragraph 148.

18 Alberta Utilities Commission, Decision 2012-237, paragraph 497.

C. Revenue adjustment at the end of the plan term

At the end of the plan term, revenues are typically adjusted (via "rebasing") to bring revenues back into line with costs. This adjustment will be positive if the utility is earning less than the authorized return and negative (ie, a revenue reduction) if the utility is earning above the authorized return. For practical purposes, rebasing is the same as a regular cost-of-service rate case.[19] I also consider it important that the approach to rebasing at the end of the plan term should be specified at the outset of the plan. If the details of what happens at the end of the plan term are only worked out part way through or at the end of the plan, or if it is not clear that there will be rebasing after five years, the resulting uncertainty would blunt the PBR incentives.

19 I have previously testified on this topic in Alberta. See *Written Evidence of Dr. Toby Brown and Dr. Paul R. Carpenter for AltaGas Utilities Inc, ATCO Electric, ATCO Gas, ENMAX Power Corporation and FortisAlberta INC*, Proceeding ID No. 20414 (section II, in particular Q/A 8–17).

III. Precedents

I have reviewed current and recently expired multi-year rate plans for electric utilities in the US and Canada. I have reviewed all US examples I am aware of, except that I have not considered rate freezes.[20] I have also not considered older plans that expired some time ago. Since there are not many such plans in the US, I have included plans that have features that are not shared with the Commission's proposal in Hawai'i,[21] and I have also included examples from the larger Canadian provinces. I also briefly discuss Australia and Great Britain.

A. US examples

I have found seven US states with examples of multi-year plans, including California and New York.[22] The seven states are listed in Table 1.

Of the seven states shown in Table 1, six have utility-specific annual revenue adjustments and only one bases the annual revenue adjustment on an external benchmark. Furthermore, New York and California apply similar plans to all of the major electric (and gas) utilities in each state.

[20] To find US examples I reviewed the 2015 Edison Electric Institute survey prepared by Pacific Economic Group Research LLC (*Alternative Regulation for Emerging Utility Challenges: 2015 Update*, November 11, 2015). Where a particular jurisdiction (eg, California) has more than one utility with a multi-year rate plan, I included only one example. I also added other utilities based on my experience. For all the utilities mentioned in this note I have reviewed the relevant decisions describing the rate plan. The distinction between a traditional rate case, a rate-freeze and a multi-year rate plan is not always clear. For example, Tampa Electric in Florida requested a rate increase in 2013 and subsequently agreed to settle the case with a lower than requested rate increase that was phased in over several years. I have not included this plan in Table 1 (see Order No. PSC-13-0443-FOF-EI, Florida Public Service Commission, September 30, 2013). I have also not included Hawai'i in Table 1.

[21] For example, I have included Puget Sound Energy's plan which caps rate increases in addition to providing for an annual revenue adjustment. (Order 07, June 25, 2013, in Dockets UE-121697 and UG-121705 (consolidated), before the Washington Utilities and Transportation Commission, p. ii.)

[22] These states are the largest and third largest by GDP, and the 2nd and 5th largest by electricity consumption. New York and California have had multi-year rate plans for their major investor-owned utilities for many years.

Table 1

Utility		State	Term	Annual Revenue Adjustment Method
PG&E	[A]	CA	2017-2019	Utility-specific
Georgia Power	[B]	GA	2014-2016	Utility-specific
Public Service Company of NH	[C]	NH	2010-2015	Utility-specific
Consolidated Edison	[D]	NY	2017-2019	Utility-specific
Northern States Power	[E]	MN	2016-2019	Utility-specific
Puget Sound Energy	[F]	WA	2013-2016	Utility-specific
Eversource	[G]	MA	2018-2023	External benchmark

Notes and Sources:

[A]: Decision 17-05-013, May 11, 2017.

[B]: Document 151108 in Docket No. 36989, December 23, 2013.

[C]: Order No. 25,123 June 28, 2010.

[D]: Order approving Electric and Gas Rate Plans, Case 16-E-0060 etc., January 25, 2017.

[E]: Docket No. E-002/GR-15-826, Findings of Fact, Conclusions and Order, June 12, 2017.

[F]: Dockets UE-121697 and UG-121705 (consolidated), Order 7, June 25, 2013.

[G] D.P.U. 17-05 November 30, 2017 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism.

Table 1 shows that there is one US example with an annual revenue adjustment based on an external benchmark. The Eversource Massachusetts plan includes annual revenue increases of inflation plus 1.56% (ie, a negative X-factor), and also includes a capital tracker for grid modernization expenditure. The tracker is expected to cover investment of about $133m over three years.[23,24] The costs covered by the tracker must fall into one of seven defined categories related to grid modernization,[25] and can include certain O&M expenses as well as capital.[26] The other utilities in Massachusetts have different plans.[27]

23 For Eversource $133m invested over three years would represent an annual addition to rate base of about 1.4% (see Table 2 below).

24 Grid Modernization Decision in the cases of DPU 15-120, 15-121, and 115-122, Massachusetts Department of Public Utilities, May 10, 2018.

25 The categories are: distribution management systems; advanced load flow analysis; VVO (conservation via voltage control); overhead automated feeder reconfiguration; underground automated feeder reconfiguration; advanced sensing; and communications. *Ibid.*, p. 172.

26 *Ibid.*, p. 222.

27 National Grid in Massachusetts has a rate plan that includes a mechanism to flow through the revenue requirements associated with capital additions, subject to certain conditions (including a cap on the level of annual additions and a cap on the total revenue requirement impact). See discussion of the Capital Investment Recovery Mechanism in D.P.U.15-155, September 30, 2016. The rate plan does not have a defined term and does not have a fixed annual revenue adjustment.

B. Canadian examples

In Canada there are multi-year rate plans in place in British Columbia, Alberta and Ontario. In Ontario the annual revenue adjustment is based on an external benchmark for O&M, but is utility-specific for capital.[28] In Alberta, the revenue adjustment[29] is an external benchmark, but there is an extra utility-specific adjustment for capital. For example, in the case of Fortis Alberta, the 2019 revenue adjustment due to I – X was about 1.8%[30] and the K-factor revenue adjustment was about 2.7%.[31] In British Columbia, BC Hydro has an external benchmark for O&M and a flow-through for capital; Fortis BC has an adjustment mechanism that results in a trend based on historical O&M and capex, less an externally-determined offset.[32]

C. Australia and Great Britain

All electric distribution and transmission utilities in Australia and Great Britain have multi-year rate plans. There are fourteen electric distribution utilities in Australia and fourteen in Great Britain. All of them have annual revenue adjustments that are utility-specific.

D. Annual revenue adjustments for capital

I described above four multi-year rate plans where the annual revenue adjustment is at least partly based on an external benchmark: Eversource in Massachusetts, Hydro One in Alberta, and Fortis in British Columbia and Alberta. In all four cases there is a mechanism for additional revenue adjustments to support capital additions. FortisBC's plan includes flow-through treatment for larger projects (projects over $20m),[33] but as I explained above it is difficult to compare the FortisBC plan with other plans because it indexes O&M and capital expenditures, rather than revenues.

Of the other three plans, all three include an additional annual revenue adjustment over and above the externally-determined benchmark to address capital. In the case of Eversource, there is a capital tracker which recovers certain expenditures on a flow through basis. The other two

28 Hydro-One has annual revenue adjustment of inflation minus an X-factor of 0.45% plus a capital factor of 1.5% to 3% per year. (Decision and Order for the Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022 for Hydro One Networks Inc. Docket No EB-2017-0049. Ontario Energy Board. March 7, 2019. P. 29, 30, 82, and 123.)

29 The multi-year rate plans in Alberta apply to rates rather than revenues for the electric utilities.

30 FortisAlberta Inc., Errata to Decision 23893-D01-2018, 2019 Annual Performance-Based Regulation Rate Adjustment Filing, January 8, 2019, paragraph 29.

31 See Table 2 below.

32 Unlike most other plans, the PBR plan for Fortis BC indexes historical O&M expenses and historical capital expenses rather than revenues. The indexed O&M and capex is applied to opening rate base to calculate revenue requirements in each year of the plan. It is therefore difficult to compare to the other plans described here.

33 BC Utilities Commission, Order G-120-15, July 22, 2015, p. 2.

(Fortis Alberta and Hydro One) have annual revenue adjustment equal to I minus X plus K, where both X and K are pre-determined amounts.

I show the magnitude of the X and K factors for these three plans in Table 2. For Eversource I was not able to calculate the magnitude of the maximum K-factor in terms of an annual revenue adjustment, but I note that it corresponds to annual rate base increase of about 1.4%.

Table 2: Summary of revenue adjustments based on an external benchmark

			Annual revenue	
			decrease due to	increase due to
State / Province	Utility		X-factor	K-factor
Massachusetts	Eversource	[A]	-1.56%	
Alberta	Fortis Alberta	[B]	0.30%	2.70%
Ontario	Hydro One	[C]	0.45%	2.19%

Notes:

In this table, a negative figure in the X-factor column represents a revenue increase. A positive figure in the K-factor column represents a revenue increase.

[A]: The Eversource decision does not indicate the likely revenue requirement of the Grid Modernization capital tracker. However, the tracker authorizes $133m over three years, equivalent to 1.4% of rate base per year.

[B]: K-bar factor estimated annual increase for 2019 through 2022.

[C]: K-factor averaged over four years, net of an additional 0.15% stretch factor.

Sources:

[A]: D.P.U. 17-05 November 30, 2017 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, p. 392.

[B]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 9.

[C]: DECISION AND ORDER EB-2017-0049 HYDRO ONE NETWORKS INC. Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022, p. 2.

Table 4 and Table 5 show the detail of the calculations.

Table 3: Eversource calculations

		$m
Rate base (NSTAR)	[A]	2,732.9
Rate base (WMECO)	[B]	436.4
Total rate base	[C]	3,169.2
Grid modernization budget	[D]	133.0
Annual rate base increase	[E]	1.4%

Notes:

[C] = [A] + [B]

[E] = [D] / 3 / [C]

Sources:

[A]: D.P.U. 17-05 November 30, 2017 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, p. 769.

[B]: D.P.U. 17-05 November 30, 2017 Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 CMR 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and a Performance Based Ratemaking Mechanism, p. 778.

[D]: Grid Modernization Decision in the cases of DPU 15-120, 15-121, and 115-122, Massachusetts Department of Public Utilities, May 10, 2018, p. 172.

Table 4: Fortis calculations

		$m or %
2017 Notional revenue requirement	[A]	513.1
2018 K-bar revenue	[B]	22.1
2019 K-bar	[C]	35.9
2018 I factor	[D]	0.10%
2018 X factor	[E]	0.30%
2018 Q factor	[F]	0.20%
2019 K-factor	[G]	-12.8
2019 I - X	[H]	1.83%
2019 Q factor	[I]	0.70%
Estimated 2018 base revenue	[J]	513.1
2019 K-bar increase over 2018 K-bar	[K]	13.9
2019 K-bar increase as % of 2018 revenue	[L]	2.7%

Notes:

[J] = [A] x (1 + [D] - [E] + [F])

[K] = [C] - [B]

[L] = [K] / [J] x 100

Sources:

[A]: FortisAlberta Inc., Summary of Revenue Requirement, Schedule 1.

[B]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 1

[C]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 1

[D]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 9

[E]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 9

[F]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 9

[G]: FortisAlberta Inc. Errata to Decision 23893-D01-2018 2019 Annual Performance-Based Regulation Rate Adjustment Filing January 8, 2019, paragraph 39.

[H]: FortisAlberta Inc. Errata to Decision 23893-D01-2018 2019 Annual Performance-Based Regulation Rate Adjustment Filing January 8, 2019, paragraph 29.

[I]: 23893_X0042_AppendixC-Updated2019PlaceholderK-BarSch_0051, Schedule 9

Table 5: Hydro One calculations

		2019	2020	2021	2022
K-factor	[A]	2.32%	2.21%	3.14%	1.69%
Average	[B]				2.34%
Less offset	[C]				-0.15%
Net	[D]				2.19%

Notes:

[B] = sum of [A] / 4

[D] = [B] + [C]

Sources:

[A]: DECISION AND ORDER EB-2017-0049 HYDRO ONE NETWORKS INC. Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022, p. 30.

[C]: DECISION AND ORDER EB-2017-0049 HYDRO ONE NETWORKS INC. Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022, p. 31.

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Cost of Capital Mechanism

August 13, 2019

Background

In California, during 1987, the determination of capital structure and ROE was transferred out of General Rate Case applications to separate annual Cost of Capital applications (for Southern California Edison (SCE) Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Gas Company (SoCal Gas).

In subsequent years, automatic adjustment mechanisms were approved, which allowed multiple years between Cost of Capital applications. Effectively, all of the major utilities in California have operated under a multi-year Cost of Capital mechanism for over ten years. The average time period between full Cost of Capital proceedings has been six years.

- 1996: SDGE adopted Market Indexed Capital Adjustment Mechanism, which allowed Cost of Capital adjustments over a five-year period by comparing bond yield to a benchmark; the mechanism included an off-ramp at 260 basis points, and required a complete filing following an off-ramp event.

- 2008: D.08-05-035 established a uniform Cost of Capital Mechanism (CCM) for each utility with a three-year term. The mechanism automatically adjusts the utility cost of capital and associated revenue requirement based on utility bond index changes in each year a utility is not required to file a cost of capital application.[1]

- A utility retains the right to file a new Cost of Capital application outside the CCM process if there is an extraordinary or catastrophic event.

- 2010: D.10-01-017 extended the 2008 Cost of Capital filing until 2013.

- 2012: D.12-12-034 established 2013 ratemaking ROE and return on rate base for utilities and remained open to finalize the CCM.

- 2013: D.13-03-015 continued the uniform CCM for each utility established in D.08-05-035 until 2016.

- 2016: D.16-02-019 extended the 2013 Cost of Capital filing until 2018.

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[1] The California utilities filed separate applications which were consolidated into one proceeding. Each utility has unique factors and differences that need to be considered in arriving at a reasonable return in three distinct areas: capital structure, long-term debt and preferred stock costs, and return on common equity.

- 2017: D.17-07-005 modified D.13-03-015 to (1) reduce the authorized ROE for each utility; (2) reset each utility's authorized cost of long-term debt and cost of preferred equity in 2018; and, (3) extended the next Cost of Capital application filing deadline to April 22, 2019.

- 2019: A.19-04-014 (015, 017,018) Cost of Capital applications filed for the 2020 test year for SCE, PGE&E, SDG&E and SoCal Gas, with a 3-year term (through 2023). Procedural schedule indicates a final decision by year end 2019.[2]

Objectives/Benefits

The Cost of Capital Mechanism:

- Reduces the time and costs associated with filing and litigating Cost of Capital proposals
- Produces objective results through readily available historical rates that eliminate the need for interest rate forecasts (and related forecasting risk)
- Represents a simple, transparent, and non-controversial adjustment mechanism (i.e., automatic adjustment rather than adjustment by litigated outcome)
- Limits frequent or abrupt changes, while remaining sensitive enough to trigger when fluctuations in the bond markets necessitate an adjustment
- Provides timely ratemaking information to stakeholders and the financial markets

Under the mechanism, changes to the utility's return between Cost of Capital proceedings are a function of historical rates based on actual market data. The CCM effectively balances the interests of shareholders and ratepayers while simplifying and reducing Cost of Capital proceedings, workload requirements and regulatory costs:

> "This CCM streamlines the major energy utilities' COC process while providing greater predictability of the utilities' COC by eliminating the use of interest rate forecasts and disputes concerning interest rate levels and trends, as well as uncertainties associated with conflicting perceptions of financial markets and the return requirements of investors. Hence, shareholders and ratepayers alike share in the burden and benefit of market changes, while eliminating the burden of annual COC applications. The CCM also enables the utilities, interested parties, and Commission staff to reduce and reallocate their respective workload requirements for litigating annual COC proceedings." (D.13-03-015, page 7)

The CCM is viewed positively by credit rating agencies and banks (who evaluate the financial condition of the utilities). The automatic rate-setting mechanism provides greater transparency in

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[2] See Appendix A for a summary of the Cost of Capital for California utilities.

understanding changes to a utility's ROE compared to the uncertainty of predicting litigation outcomes, and promotes stability.

Components

In the separate cost of capital proceeding, the Commission determines a utility's Cost of Capital in a three-step process:

1. First, adopts a capital structure – the proportion of debt to equity that a utility should use to finance its capital investments.
2. Second, calculates the company's cost of debt, based on the actual cost of the company's outstanding debt during the relevant period (includes embedded cost of long-term debt[3] and preferred equity).
3. Third, determines the appropriate common equity return (ROE) for the utility by examining returns for businesses with comparable risks and adequate to enable a utility to attract investors to finance the replacement and expansion of a utility's facilities to fulfill its public utility obligation.

In the cost of capital proceeding, the Commission also determines the benchmark and deadband for the CCM, as described below. After the Commission renders a decision on the cost of capital, the utility flows through the new cost of capital into rates and submits tariffs for the new rates with an effective date of January 1.

The CCM starts with the most recently adopted Cost of Capital filing[4] which established:

- A Benchmark based on the applicable utility bond index interest rate (Moody's, S&P and based on the utility's credit rating), which
    - gauges the changes in interest rates that also indicate changes in the equity costs of utilities[5]
    - is set by the Cost of Capital decision and reset when a utility's ROE is adjusted

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[3] Short-term debt is used to support regulatory balancing accounts, and is recovered in the annual true-up of those accounts.

[4] See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M283/K563/283563014.PDF for an example of a Cost of Capital Application for SCE.

[5] Utility bonds are used rather than U.S. Treasuries since utility bonds are generally less affected by major shifts in international capital markets. The utility bond index includes only utilities, and is a proxy for tracking changes in utility cost of capital components (utility cost of debt and equity), and an indicator of the changes in expected return on equity required to attract investors.

- A Deadband around the Benchmark, forming a range in bond interest rates that may occur without automatically triggering a change in embedded long-term debt and preferred stock costs and ROE.[6]
  - The size of the Deadband affects the rate at which an adjustment mechanism is activated. A Deadband that is overly sensitive to interest rates cause needless volatility in revenues and rates; a Deadband that never triggers can impose unnecessary costs on shareholders or ratepayers, depending on which direction rates move.
  - A +/-100-basis point Deadband using a 12-month average measurement period mitigates volatility of interest rates.
- The utility monitors the utility bond index for the period October 1 (of the previous year) to September 30 (of the current year) and calculates the 12-month average for that period, and compares it to the Benchmark.
- Data Source for utility bond interest rates - historical Moody's monthly utility bond interest rate index - is available through subscription services from Moody's.
- In any year where the difference between (1) the 12-month October through September average Moody's utility bond interest rates and (2) the Benchmark, exceeds the Deadband, an automatic ROE adjustment is triggered effective on January 1 of the next year, which includes:
  - The 12-month October through September utility bond interest rate average that triggered the ROE adjustment becomes the new Benchmark.
  - The ROE adjustment is calculated that is equal to 50% of the difference between the old Benchmark and new Benchmark. The ROE adjustment is applied to the total basis point difference between the old and new interest rate benchmark.[7] The adjustment ratio reflects the change in interest rates that should be reflected in the return on equity.
    - For example, if the difference between the 12-month average utility bond interest rates and the Benchmark is 1.2% and falls outside of the Deadband, then the ROE adjustment is 0.6% (50% of 1.2% is 0.6%). Then, if the currently authorized ROE is 9.5%, the new ROE will be 9.5% + 0.6%, or 10.1%.

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6 Appendix B and C provide an illustration of Benchmarks and Deadbands for SDG&E and PG&E.

7 The equity adjustment ratio of is applied to the authorized ROE in the same direction as the interest rate changes. "An application of the equity adjustment rate on only the basis points that exceeded a 100-basis point deadband would not reasonably reflect the volatility impact of interest rate changes on an equity investment" (D.08-05-035, page 15).

    - Long-term debt and preferred stock costs are updated to reflect actual August month-end embedded costs in that year and forecasted interest rates for variable long-term debt and new long-term debt and preferred stock scheduled to be issued.

- There is an Off-ramp which allows a utility to file a cost of capital application outside of the CCM process due to an extraordinary or catastrophic event that materially impacts Cost of Capital/capital structure and affects the utility differently than the overall financial markets.

Implementing an ROE Adjustment

In October of the year where an ROE Adjustment is triggered, the change is implemented as follows:

- Recalculate the ROE and long-term debt and preferred stock costs:
    - New ROE = Currently authorized ROE + ½ (new Benchmark - current Benchmark)
    - Updated Long-term Debt costs = Actual embedded cost of long-term debt through September + new debt issuances - debt maturities forecasted for the remainder of the current year through the next year
    - Updated Cost of Preferred Stock Cost = true-up for any issuance or redemption of preferred stock for the current year through the next year
- Recalculate the total revenue requirement (update results of operations model) using these new costs.[8]
- Submit a tariff transmittal to the Commission, presenting the changes to ROE, costs of long-term debt and preferred stock, and change in revenue requirements effective on January 1st.

Duration of the Mechanism

The Cost of Capital Mechanism is effective for a three-year period, prior to a complete Cost of Capital rate-setting application. This duration between applications allows the utility to gain meaningful experience with the mechanism, and streamline the regulatory process. In addition, utilities may petition the Commission for an extension of the most recent Cost of Capital decision if no changes are required. As mentioned earlier, the average duration between full Cost of Capital proceedings has been about six years.

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[8] If a change in the Cost of Capital occurs during an attrition year, the revenue requirement will be calculated using the authorized attrition year rate base.

Effect on Other Rate Proceedings

In filing a rate case, or other rate-setting proceeding, the currently authorized Cost of Capital will be used to determine the revenue requirement for the test year. If there is a change in the Cost of Capital while a rate case proceeding is ongoing, the results of operations and revenue requirements will be updated. If a change in the Cost of Capital occurs after a rate case decision is issued, the rate case decision's revenue requirements will be updated with the new Cost of Capital consistent with the effective date of the Cost of Capital (and applied to the authorized rate case rate base).[9]

Illustrative Timeline for Implementing the Cost of Capital Mechanism

Figure 1, below, illustrates the Cost of Capital mechanism over the three-year period, and is followed by Figure 2, which provides further detail on the steps and regulatory filings supporting the Cost of Capital and Mechanism.

Figure 1: Timeline for Cost of Capital Mechanism over 5-Year Period

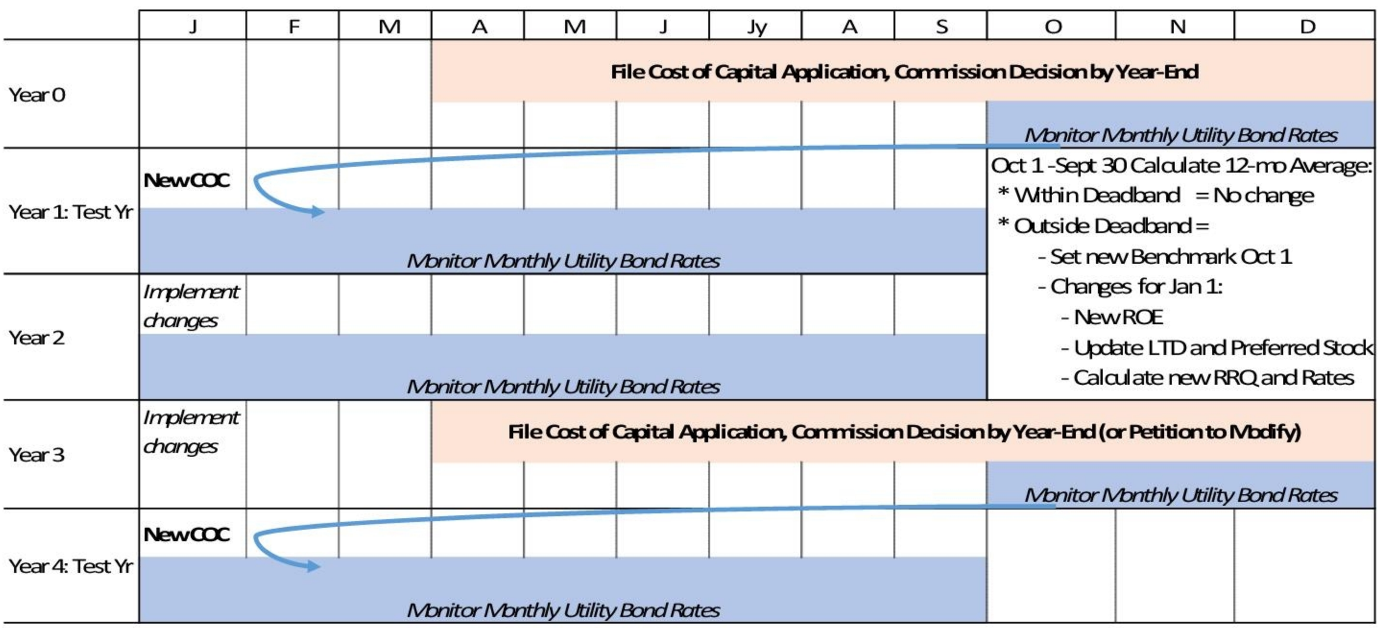

Figure 1 Notes:

1. The Cost of Capital is a rate-setting application and covers a five-year term.
2. The 12-month Average is a simple average of Moody's Utility Bond Index.
3. If an ROE change is triggered --- the new Benchmark is the 12-month Average and effective October 1 of the trigger year.

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9 In California, since the Cost of Capital proceeding consolidates the requests of 4 utilities, the Cost of Capital decision is usually not be coincident with a general rate case decision.

4. If an ROE change is triggered ---- the change in ROE is 50% of the difference of the new Benchmark and the current Benchmark, and is effective on January 1, along with updated costs for Long-term Debt and Preferred Stock.
5. LTD = Long Term Debt
6. RRQ = Revenue Requirements

Figure 2: Filings Supporting the Cost of Capital Mechanism over 3-Year Period

Filing Description	Filing Date	Accrual of New Costs/Credits	Change in Rates
1. Application for Cost of Capital Rate-setting proceeding, to establish: • ROE, Long-term Debt and Preferred Stock costs • Cost of Capital Mechanism (Deadband, Benchmark, other features)	April 1, Year 0	Jan 1, Year 1	Jan 1, Year 1
2. Year 1 Cost of Capital implementation: • Calculate results of operations change (revenue requirements using the authorized rate base), and • Prepare Tariff Transmittal to implement changes to ROE, Long-term Debt, Preferred Stock changes, Benchmark, with an effective date of January 1, Year 1 for related rate adjustments.	October 15, Year 0	Jan 1, Year 1	Jan 1, Year 1
3. Year 2 Cost of Capital Mechanism: Calculate 12-month Average ROE (Oct 1, Year 0 through Sept 30, Year 1, Moody's utility bond index) and compare to Benchmark. 4. If 12-month Average is within the Deadband, no change. 5. If 12-month Average is outside the Deadband, calculate: • New ROE = Authorized ROE + ½ (12-month Average – Benchmark) • Updated Long-term Debt costs • Updated Preferred Stock costs • New Benchmark = 12-month Average	October 15, Year 1	Jan 1, Year 2	Jan 1, Year 2

Filing Description	Filing Date	Accrual of New Costs/Credits	Change in Rates
6. Calculate results of operations change (revenue requirements using the authorized rate base), and rate changes. 7. Prepare Tariff Transmittal to implement changes to ROE, Long-term Debt, Preferred Stock changes, Benchmark, with an effective date of January 1 for related rate adjustments.			
8. Year 3 Cost of Capital Mechanism: Calculate 12-month Average ROE (Oct 1, Year 3 through Sept 30, Year 2, Moody's utility bond index) and compare to Benchmark. 9. If 12-month Average is within the Deadband, no change. 10. If 12-month Average is outside the Deadband, calculate: • New ROE = Authorized ROE + ½ (12-month Average – Benchmark) • Updated Long-term Debt costs • Updated Preferred Stock costs • New Benchmark = 12-month Average 11. Calculate results of operations change (revenue requirements using the authorized rate base), and rate changes. 12. Prepare Tariff Transmittal to implement changes to ROE, Long-term Debt, Preferred Stock changes, Benchmark, with an effective date of January 1 for related rate adjustments.	October 15, Year 2	Jan 1, Year 3	Jan 1, Year 3
13. Year 3 Application for Cost of Capital Rate-setting proceeding, to establish: • ROE, Long-term Debt and Preferred Stock costs • Cost of Capital Mechanism (Deadband, Benchmark, other features) (Alternatively, file petition to modify current Cost of Capital, to extend the duration.)	April 1, Year 3	Jan 1, Year 4	Jan 1, Year 4

Appendix A: Current and Proposed Cost of Capital for California Utilities

	Current 2017-2019				Proposed 2020-2023*		
	Component	Percentage	Cost	Weighted Cost	Percentage	Cost	Weighted Cost
		(a)	(b)	(a x b) = c	(a)	(b)	(a x b) = c
SCE	Long-Term Debt	43.0%	4.7%	2.04%	43.0%	4.74%	2.04%
Moody's	Perferred Equity	9.0%	5.7%	0.51%	5.0%	5.70%	0.29%
long-term	Common Equity	48.0%	10.3%	4.94%	52.0%	11.45%	5.95%
Baa utility						(AB 1054)	
	Total	**100.0%**		**7.50%**	**100.0%**		**8.28%**
PGE	Long-Term Debt	47.5%	4.89%	2.32%	47.5%	5.16%	2.45%
Moody's	Perferred Equity	0.5%	5.60%	0.03%	0.5%	5.52%	0.03%
long-term	Common Equity	52.0%	10.25%	5.33%	52.0%	12.00%	6.24%
Baa utility						(AB 1054)	
	Total	**100.0%**		**7.69%**	**100.0%**		**8.72%**
SDGE	Long-Term Debt	45.25%	4.59%	2.08%	44.00%	4.59%	2.02%
Moody's	Perferred Equity	2.750%	6.22%	0.17%	0.00%	0.00%	0.00%
long-term	Common Equity	52.00%	10.20%	5.30%	56.00%	12.38%	6.93%
Baa utility						(AB 1054)	
	Total	**100.0%**		**7.55%**	**100.0%**		**8.95%**

** A.19-04-014, 015, 016 Updated testimony August 9, 2019*

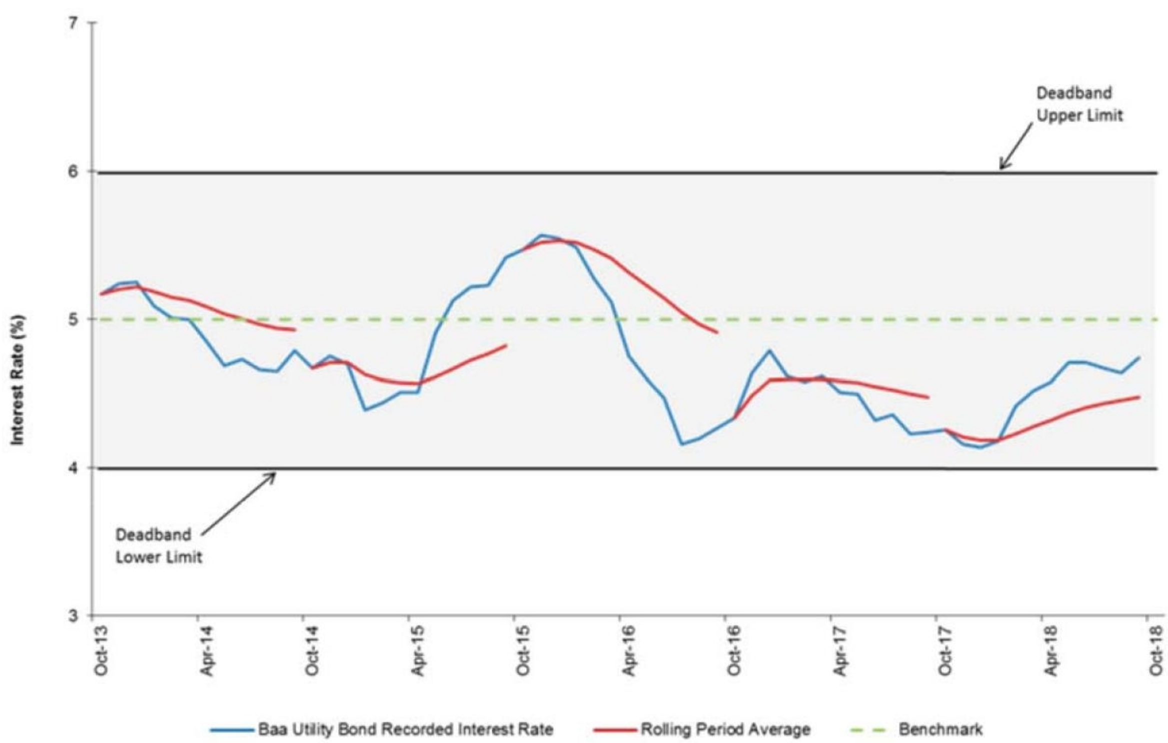
Appendix B: Benchmark/Deadband: SDG&E

From A.19-04-017, an example of the Target, Deadband, and 12-month average utility bond yields for San Diego Gas and Electric from 2012 to 2018. The figure indicates that over the past six years, the CCM has not triggered a change in the ROE.

Appendix C: Benchmark/Deadband: PG&E

From A.19-04-015 page 6-2, an example of the Target, Deadband, and 12-month rolling average (instead of a simple 12-month average) utility bond yields for Pacific Gas & Electric from 2012 to 2018. The figure indicates that over the past six years, the CCM has not triggered a change in the ROE using a rolling average.

From A.19-04-15, an example of the Target, Deadband, and 12-month average utility bond yields for Pacific Gas and Electric from 2012 to 2018. The figure indicates that over the past six years, the CCM has not triggered a change in the ROE.



PBR – RATE DESIGN BETWEEN RATE CASES

In Phase 2 of the PBR proceeding (Docket 2018-0088), the Commission outlined its vision for a performance based ratemaking framework which included extending the period between rate cases from the current three years to five years. This extended period has significant implications for rate design and the process for adjusting rates during the rate period.

Existing Rate Design Structure

Under the current arrangements, each of the Companies files a rate case once every three years. The rate case determines:

- Rate case target revenues
- Energy Cost Recovery Clause
- Purchase Power Adjustment Clause
- Base rates
- Revenue Balancing Account
- Other attrition mechanisms

Energy Cost Recovery Clause recovers the cost of fuel and purchased energy based on a flat energy rate (i.e., ¢/kWh)[1]. This rate is adjusted monthly to reflect estimated energy costs and an adjustment to allowed energy costs that is reconciled quarterly. Although these costs are primarily caused by the quantity of energy used by customers, an extended rate period would not impact the present flat energy rate form of ECRC; however, this rate should be reviewed periodically to provide better price signals that encourage more efficient use of electricity by customers and provide customers choices and opportunities to lower their bills.

The Purchased Power Adjustment Clause recovers the cost of non-energy purchased power expenses such as capacity and O&M. These rates are adjusted monthly to reflect actual non-energy purchased power costs. Costs are allocated to each customer class based on demand and energy as determined in the most recent rate case which final rates are approved by the Commission. Within a customer class, costs are allocated based on energy. An extended rate period should not significantly impact the present flat energy rate form of ECRC; however, this rate should be reviewed periodically to provide better price signals that encourage more efficient use of electricity by customers and provide customers choices and opportunities to lower their bills.

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[1] The Energy Cost Recovery Clause is also adjusted for fossil fuel cost risk sharing for Hawaiian Electric, Maui Electric (effective September 1, 2019) and recovers non-adjustable fuel expense on fixed cents per kWh basis.

Base rates recover the cost to provide electrical service to customers, excluding recovery of fuel and purchased power. These rates are fixed between rate cases. Base rates strive to reflect cost causation as informed by cost of service studies and allocate costs to customers fairly based on how much it costs to connect and bill a customer, how they use electricity and the quantity of electricity they use for each classification of customers. The basic types of charges are the customer charge, demand charge and energy charge.

The Companies have a decoupling mechanism which provides for any under- or over-collection of revenues to be collected (or returned) in the following year, via the Revenue Balancing Account (RBA). The RBA ensures that the authorized "Target Revenue" will be collected (Target Revenue excludes certain items of the revenue requirement, principally fuel and purchased power expenses). In addition, the Revenue Adjustment Mechanism (RAM) and Major Project Interim Recovery (MPIR), which provide for limited recovery of changes in costs, adjust the Target Revenues each year and are recovered through the RBA Rate Adjustment.

In the first year of the rate period, 100% of the Target Revenue is collected in base rates using the rate structure determined in the rate case. By the third year of the rate cycle, a significant proportion of target revenue is collected through the RBA Rate Adjustment. While base rates (depending on the customer class) contain kWh, fixed and demand rate elements, the RBA Rate Adjustment is recovered only via kWh charges. Furthermore, the Companies' rate design tends to recover a significant amount of the Companies' fixed costs in kWh charges (for example, Hawaiian Electric's cost of service study in 2017 allocated about $100 million of costs to the residential customer charge, but the approved 2017 rate structure collects only about $30 million in residential customer charges). Similarly, commercial customers have rate structures that recover a greater portion of fixed costs through demand charges as well as the customer charge. Thus, historically over time as kWh sales decline and the RAM provides attrition, the proportion and amount of fixed costs collected in kWh charges have increased.

Other attrition mechanisms such as the Renewable Energy Infrastructure Program, Demand Side Management and Demand Response Management System surcharges provide recovery of costs between rate cases. The rate mechanism is addressed in the application for cost recovery, and therefore, would not be affected by a longer rate period.

<u>Consequences for rate design of extending the rate period</u>

Extending the current three-year cycle of rate cases to five years is intended to strengthen the incentive to control costs during the rate period, and to increase the efficiency of the regulatory process.

Extending the rate period could cause difficulties for rate design, in two ways. First, current practice is for rate design to be addressed as part of the rate case. By implication, therefore, extending the period between rate cases would also increase the length of time

between opportunities to adjust rate structure. It may be important to adjust rate structure more frequently in the future, due to the significant anticipated changes associated with Hawai'i's energy transition. Second, as explained above, during the rate period an "imbalance" builds up as an increasing amount (in $ and % terms) of Target Revenue is recovered in kWh charges. At the next rate case, other things being equal, there will be a step increase in fixed costs and demand charges as revenues collected in the RBA through kWh charges shift into base revenues where they are collected through a mix of kWh, demand and fixed charges. As the rate period is lengthened, the magnitude of the required step change at the next rate period will increase. The fact that there is a step change at the rate case shows that RBA revenue, allocated 100% to kWh charges, is allocated differently when it becomes part of base revenue at the time of the next rate case. This demonstrates an inconsistency: whatever principles are being used to guide the design of base rates, these principles are not being used to guide the design of rates to recover RBA revenue. We are not aware of any reason for such an inconsistency to be designed into the regulatory framework.

We can illustrate the inconsistency with a simple example. Suppose that between year 1 and year 2 of the rate period there are no changes at all except that kWh sales decrease by 1%, with all other billing determinants remaining constant. Assume that costs remain constant, and ignore for the moment the RAM revenue adjustment. The reduction in sales will result in a shortfall in Target Revenue of a little less than 1% (because there are some fixed and demand charge revenues). As a result, the RBA Rate Adjustment, which charges on a kWh basis, will have to increase by around 1% to collect the missing sales revenue. kWh charges have increased by 1%, yet marginal costs have not changed.

One way of avoiding or at least reducing these difficulties would be to separate proceedings for redesigning base rates on a revenue neutral basis from the proceeding to set authorized revenues (i.e., take rate design out of the rate case). The period between rate cases could be lengthened, while retaining the ability to redesign base rates more frequently. With the RBA in place, adjusting the design of base rates would not change the total amount of revenue collected, which would continue to be determined in the rate case and by the operation of the RAM or successor mechanism. We are not aware of any principles suggesting that revenue neutral rate design must happen in a rate case.

Another solution would be to change the way that revenue to be recovered through the RBA is reflected in rates. Currently this revenue is collected entirely through a kWh charge. A simple alternative might be to recover RBA revenue through a flat percentage increase to all rate elements (ie, increase fixed charges, demand charges, and kWh charges by the same percentage). Another alternative might be to process the RBA revenue through the same cost allocation and rate design methodology as was used to set base rates, or to define a more cost-reflective methodology for allocating RBA revenue to rate elements.

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing document, together with this Certificate of Service, were duly served on the following parties and participants, by having said copies delivered by electronic service, by hand delivery, and/or by mailing a copy by United States mail, postage prepaid, as set forth below:

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DATED: Honolulu, Hawai'i, August 14, 2019.

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